Advanced Transmission Technologies

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John Hauer
Pacific Northwest National Laboratory
Richland, Washington

Tom Overbye
University of Illinois at Urbana-Champaign
Urbana, Illinois

Jeff Dagle
Pacific Northwest National Laboratory

Steve Widergren
Pacific Northwest National Laboratory

Introduction

This paper discusses the use of advanced technologies to enhance performance of the national transmission grid (NTG). We address present and developing technologies that have great potential for improving specific aspects of NTG performance, strategic impediments to the practical use of these technologies, and ways to overcome these impediments in the near term.

Research and development (R&D) infrastructure serving power transmission is as badly stressed as the grid itself, for many of the same reasons. The needs are immediate, and the immediate alternatives are few. Timely and strategically effective technology reinforcements to the NTG need direct, proactive federal involvement to catalyze planning and execution. Longer-term adjustments to the R&D infrastructure may also be needed, in part energy policy can evolve as the NTG evolves.

Technology and a coordinated national effort are only two of the elements necessary for timely resolution of the problems facing the national energy system. Sustainable solutions require careful balancing between generation and transmission, profit and risk, the roles of public and private institutions, and market forces and the public interest. There is a vast body of information and opinion on these issues. A recent white paper by EPRI (formerly known as the Electric Power Research Institute) clearly lays out the broad issues and a comprehensive inventory of technology options for enhancing the grid, including detailed assessments of their direct costs and benefits. Titled "The Western States Power Crisis: Imperatives and Opportunities," (EPRI 2001), this document notes that "…the present power crisis—most evident in the Western states but potentially a national problem—requires a fundamental reassessment of the critical interactive role of technology and policy in both infrastructure and markets" (EPRI 2001). Similar assessments of needs and solutions, many of which arrive at similar conclusions, are found in a series of studies extending back to 1980 (DOE 1980). A widely shared view concerning the urgency of technology solutions is provided in Scherer 1999.

The strategic need is not just for new technology in the laboratory but for an infusion of improved, cost-effective technology to work in the power system. The chief impediments to infusion are institutional and can be resolved by a proactive national consensus regarding institutional roles. Until this consensus is achieved, the lack of cohesion between technology and policy may be disruptive for continued development of the NTG and the infrastructures that it serves.

This issue paper discusses the use of new technologies to enhance the performance of the NTG, as follows:

- Background on power system operation in general and the specifics of the NTG.
- The new demands being placed on the NTG and outlines the technology needed to address these demands.
- The impact of existing institutional frameworks on the application of new technology to the transmission grid.
- The strategic challenges that can be addressed through accelerated use of selected new technologies.
- The institutional issues associated with moving new technology from the research laboratory to deployment in the grid.
- A summary of some of the options discussed in the paper.
- Appendix A is an extensive (though not exhaustive) list of new technologies that could be applied to the NTG.

Background

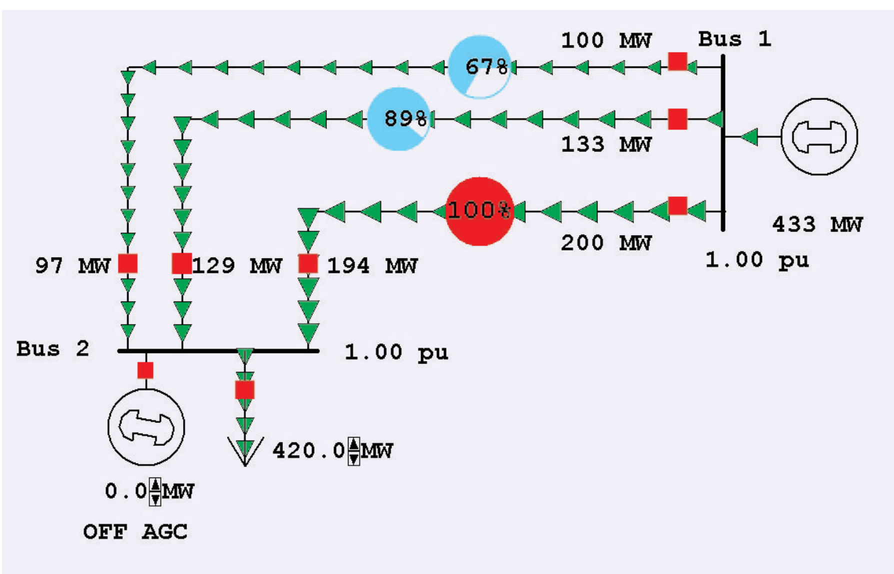
The transition to open electrical energy markets is stressing the NTG beyond its design capabilities. Less conspicuously, this transition is also stressing the management infrastructure by which transmission facilities are planned, developed, and operated. Stresses on this infrastructure are a major strategic impediment to the focused development and timely deployment of technical solutions to shortfalls in national grid capacity. The subsections below give some transmission system background that is necessary to understand these technological issues.

Power System Components and Reciprocal Impacts

The power system has three components: generation, load, and transmission. Electric power is produced by generators, consumed by loads, and transmitted from generators to loads by the transmission system. Typically, the "transmission system" (or "the grid") refers to the high-voltage, networked system of transmission lines and transformers. The lower-voltage, radial lines and transformers that actually serve load are referred to as the "distribution system." The voltage difference between the transmission system and the distribution system varies from utility to utility; 100 kV is a typical value. This paper focuses only on advanced technologies for the transmission system.

It is important to understand reciprocal impacts among the transmission system, load, and generation. Because the transmission system's job is to move electric power from generation to load, any technologies that change or redistribute generation and/or load will have a direct impact on the transmission system. This can be illustrated using a simple two-bus, two-generator example shown in one-line form in Figure 1. The solid lines represent the buses, the circles represent the generators, and the large arrow represents the aggregate load at bus 2. Three transmission lines join the generator at bus 1 to the load and generation at bus 2. Superimposed on the transmission lines are arrows whose sizes are proportional to the flow of power on the lines. The pie charts for each line indicate the relation between the loading on each line and its rated capacity. The upper and middle transmission lines have a rating of 150 MVA, and the lower line has a rating of 200 MVA. In addition, we assume that the bus 1 generation is more economical than the generation at bus 2, and the entire load is being supplied remotely from the bus 1 generator. With a bus 2 load of 420 MW, the power distributes among the three lines based on their impedances (which are not identical), so the upper line is loaded at 67 percent, the middle at 89 percent, and the lower at 100 percent. Note: there are 13 MW of transmission line losses in this case.

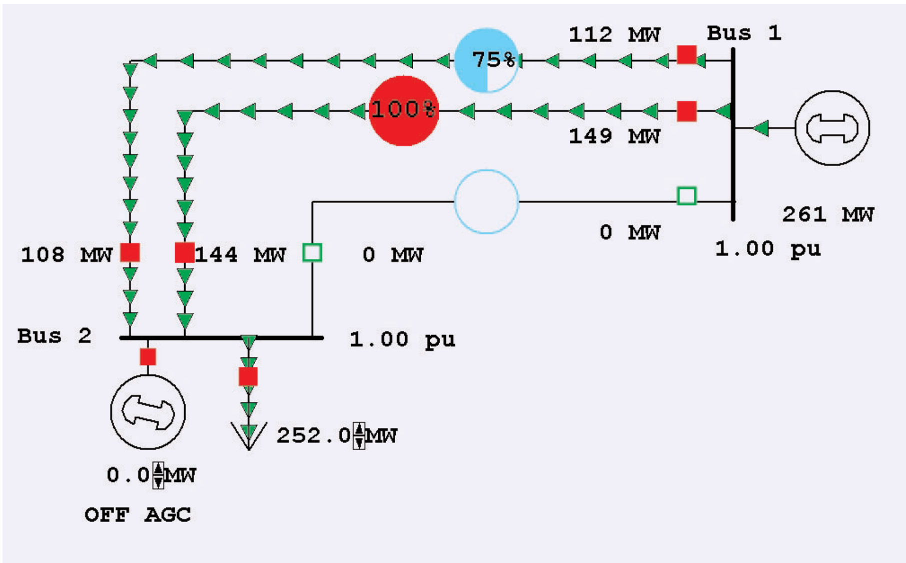
Figure 1: Two-Bus Example with No Local Generation



Transfer Capacity

A natural question to ask is: what is the transfer capacity of the transmission system described in Figure 1? That is, how much power can be transferred from bus 1 to bus 2? The answer is far from straightforward. At first glance, the transfer capacity appears to be 420 MW because this amount of power causes the first line to reach its limit. However, this answer is based on the assumption that all lines are in service. As defined by the North American Electric Reliability Council (NERC), transfer capacity includes consideration of reliability. A typical reliability criterion is that a system be able to withstand the unexpected outage of any single system element; this is known as the first contingency total transfer capability (FCTTC). Based on this criterion, Figure 2 shows the limiting case with an assumed contingency on the lower line, which results in a transfer capability of only 252 MW. Which number is correct?

Figure 2: Two-Bus Example with Limiting Contingency



The answer depends on system operational philosophy and on the availability of high-speed system controls. If the operational philosophy requires that no load be involuntarily lost following any individual contingency, and if there are no mechanisms to quickly increase the generation at bus 2, voluntarily decrease the load at bus 2, or redistribute the flow between the remaining upper two lines, then the limit would be 252 MW. With these limitations, the only way to increase the transfer capacity would be to construct new lines.

However, if we relax one or more of these conditions, the transfer capacity could be increased without construction of new lines. For example, one approach would be to provide at least some of the bus 2 load with incentives so that, following the contingency, some customers on bus 2 would voluntarily curtail their loads. Incentives might involve price-feedback mechanisms or agreements to allow the system operator to curtail load through some type of direct-control load management or interruptible demand. Another approach would be to have a mechanism for quickly committing some local bus 2 generation. Availability of local generation reduces the net loading on the transmission system and can increase its capacity. A third approach would be to use advanced power electronics controls such as flexible AC transmission system (FACTS) devices to balance the load between the upper two lines.

The unifying themes of these alternative approaches are knowledge about the real-time operation of the system, availability of effective controls, and an information infrastructure that permits effective use of the controls. To understand these themes, it is important to understand the complexity of the actual national transmission grid.

Complexity of the National Transmission Grid

The term "national transmission grid" is something of a misnomer. The North American transmission grid actually consists of four large grids, each primarily a synchronous alternating current (AC) system. Together, these four grids span parts of three sovereign countries (U.S., Canada, and Mexico). By far the largest grid is the Eastern Interconnection, which supplies power to most of the U.S. east of the Rocky Mountains as well as to all the Canadian provinces except British Columbia, Alberta, and Quebec. The Western Interconnection supplies most of the U.S. west of the Rockies, as well as British Columbia, Alberta, and a portion of Baja, California. The remaining two grids are the Electric Reliability Council of Texas (ERCOT), which covers most of Texas, and the province of Quebec. In contrast to the two-bus example presented above, the Eastern and the Western Interconnections contain tens of thousands of high-voltage buses and many thousands of individual generators and loads. Because the individual grids are asynchronous with one another, no power can be transferred among them except in small amounts through a few back-to-back direct current (DC) links. Several major DC transmission lines are also used within the individual grids for long-distance power transfer.

At any given time the loading on the grid depends on where power is being generated and consumed. Load is controlled by millions of individual customers, so it varies continuously. Because electricity cannot be readily stored, generation must also vary continuously to track load changes. In addition, the impedances of the many thousands of individual transmission lines and transformers dictate grid loading. With several notable exceptions, there is no way to directly control this flow—electrons flow as dictated by the laws of physics. Because electricity propagates through the network very rapidly, power can be transferred almost instantaneously (within seconds) from one end of the grid to the other. In general, this interconnectivity makes grid operations robust and reliable. However, it also has a detrimental effect if the grid fails; failures in one location can quickly affect the entire system in complex and dramatic ways, and large-scale blackouts may result.

The grid's ability to transfer power is restricted by thermal flow limits on individual transmission lines and transformers; minimum and maximum limits on acceptable bus-voltage magnitudes; and region-wide transient, oscillatory, and voltage-stability limitations. Given NERC's reliability requirements, these limits must be considered not only for current and actual system operating point but also for a large number of statistically likely contingent conditions as well. The complexity of maximizing the power transfer capability of the grid while avoiding stressing it to the point of collapse cannot be overstated.

Technologies to Increase Transfer Capacity

The goal of this issue paper is to examine technologies that can be used to increase the grid's power-transfer capability. This increase can be achieved by a combination of direct technical reinforcements to the grid itself along with indirect information and control reinforcements that improve grid management practices and infrastructure.

Direct reinforcement of the grid includes new construction and broad use of improved hardware technology. Strategic decisions regarding these two types of improvements are a function of grid management—planning, development, and operation. Grid management involves recognizing transmission needs, assessing options for meeting those needs, and balancing new transmission assets and new operating methods. Timely development and deployment of requisite technology are essential to reinforcing the grid. Requisite technology may not mean new technology. There is a massive backlog of prototype technology that can, given means and incentives, be adapted to power system applications.

Indirect grid reinforcement includes improving grid management by means of technology. Historically, the transmission system was operated with very little real-time information about its state. During the past few decades, advances in computer and communication technology in general and SCADA (supervisory control and data acquisition) and EMS (energy management system) technology in particular have greatly improved data capabilities. Significant real-time data are now available in almost every control center, and many centers can conduct advanced on-line grid analysis. Despite these improvements, more can and should be done. In the control center, additional data need to be collected, better algorithms need to be developed for determining system operational limits, and better visualization methods are needed to present this information to operators. Beyond the control center, additional system information needs to be presented to all market participants so that they can make better-informed decisions about generation, load, and transmission system investments.

Institutional Issues that Affect Technology Deployment

In order to effectively discuss the role of advanced transmission technologies, we have to consider how their deployment is either hindered or encouraged by institutional issues. Ultimately, the bottom line is economics—technologies that are viewed as cost effective will be used, and those that are considered too costly will not. The issue of cost is not simple; public policy must address how costs and benefits should be allocated. For example, it is difficult to beat the economics of traditional overhead transmission lines for bulk power transfer. The lines are cheap to build and entail relatively few ongoing expenses. But the siting of new transmission lines is not so simple; right of way may be difficult to obtain, and new lines may face significant public opposition for a variety of reasons from aesthetic to environmental (for a detailed discussion, see Issue Paper *Transmission Siting and Permitting* by D. Mayer and R. Sedano.) Advanced technologies can reinforce the grid, minimizing the need for new overhead lines, but usually at higher cost than would be paid to build overhead lines. The challenge is to provide incentives that will encourage the desired transmission investments.

Unfortunately, in recent years the uncertainties associated with electricity industry restructuring have hampered progress in transmission reinforcement. The boundaries between responsibilities for operation and planning were once clearly delineated, but these responsibilities are now shifting to restructured or entirely new transmission organizations. This process is far from complete and has greatly weakened the essential dialogue between technology developers and users. Development of new technology must be closely linked to its actual deployment for operational use. Together, these activities should reflect, serve, and keep pace with the evolving infrastructure needs of transmission organizations. The current uncertainty discourages this cohesiveness.

The details and the needs of the evolving infrastructure for grid management are unclear, and all parties are understandably averse to investments that may not be promptly and directly beneficial. Some utilities are concerned that transmission investments may be of greater benefit to their competitors than to themselves. In the near term, relief of congestion may actually harm their businesses. As a result of such forces, many promising technologies are stranded at various points in route from concept to practical use. Included are large-scale devices for routing power flow on the grid, advanced information systems to observe and assess grid behavior, real-time operating tools for enhanced management of grid assets, and new system planning methods that are robust in relation to the many uncertainties that are present or are emerging in the new power system.

Another important issue is that some technologies that would enable healthy and reliable energy commerce are not perceived as profitable enough to attract the interest of commercial developers. Special means are needed to develop and deploy these technologies for the public good. Involvement by the federal utilities and national laboratories may be necessary for timely progress in this area, as well as a broadening of some activities of EPRI or similar umbrella organizations focused on energy R&D along with development of better mechanisms to spur entrepreneurial innovation.

New Demands on the Transmission Grid

The core objective underlying electricity industry restructuring is to provide consumers with a richer menu of potential energy providers while maintaining reliable delivery. Restructuring envisions the transmission grid as flexible, reliable, and open to all exchanges no matter where the suppliers and consumers of energy are located.

However, neither the existing transmission grid nor its current management infrastructure can fully support such diverse and open exchange. Transactions that are highly desirable from a market standpoint may be quite different from the transactions for which the transmission grid was designed and may stress the limits of safe operation. The risks they pose may not be recognized in time to avert major system emergencies, and, when emergencies occur, they may be of unexpected types that are difficult to manage without loss of customer load.

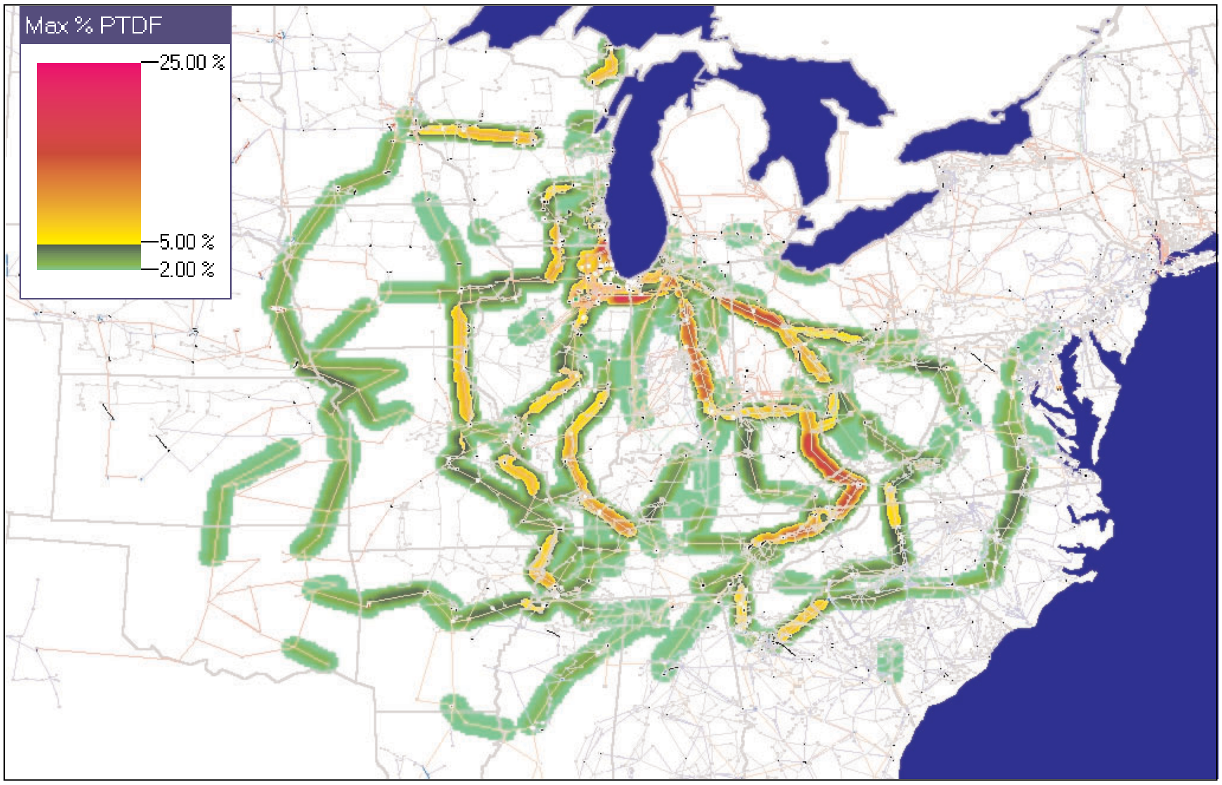
The transmission system was originally constructed to meet the needs of vertically integrated utilities, moving power from a local utility's generation to its customers. Interconnections between utilities were primarily to reduce operating costs and enhance reliability. That is, if a utility unexpectedly lost a generator, it could temporarily rely on its neighboring utilities, reducing the costs associated with having sufficient reserve generation readily available. The grid was not designed to accommodate large, long-distance transfers of electric power.

One of the key problems in managing long-distance power transfers is an effect known as "loop flow." Loop flow arises because of the transmission system's uncontrollable nature. As power moves from seller to buyer, it does not follow any prearranged "contract path." Rather, power spreads (or loops) throughout the network. As an example, Figure 3 shows how a transmission of power from a utility in Wisconsin to the Tennessee Valley Authority (TVA) would affect lines through a large portion of the Eastern Interconnection. A color contour shows the percentage of the transfer that would flow on each line; lines carrying at least two percent of the transfer are contoured. As this figure makes clear, a single transaction can significantly impact the flows on hundreds of different lines.

The problem with loop flow is that, as hundreds or thousands of simultaneous transactions are imposed upon the transmission system, mutual interference develops, producing congestion. Mitigating congestion is technically difficult, and very complex problems emerge when paths are long enough to span several regions that have not had to coordinate such operations in the past. These problems include (but are not limited to) the lack of: effective procedures, operating experience, computer models, and integrated data resources. The sheer volume of data and information concerning system conditions, transactions, and events is overwhelming the existing grid management's technology infrastructure.

Increasing the transfer capacity of the NTG will require combined application of hardware and information technologies. On the hardware side, many technologies can be developed, refined, or simply installed to directly reinforce current transmission capabilities. These technologies range from passive reinforcements (such as new AC lines built on new rights of way or better use of existing AC rights of way by means of

Figure 3: Loop Flow of Power Transfer from Wisconsin to TVA



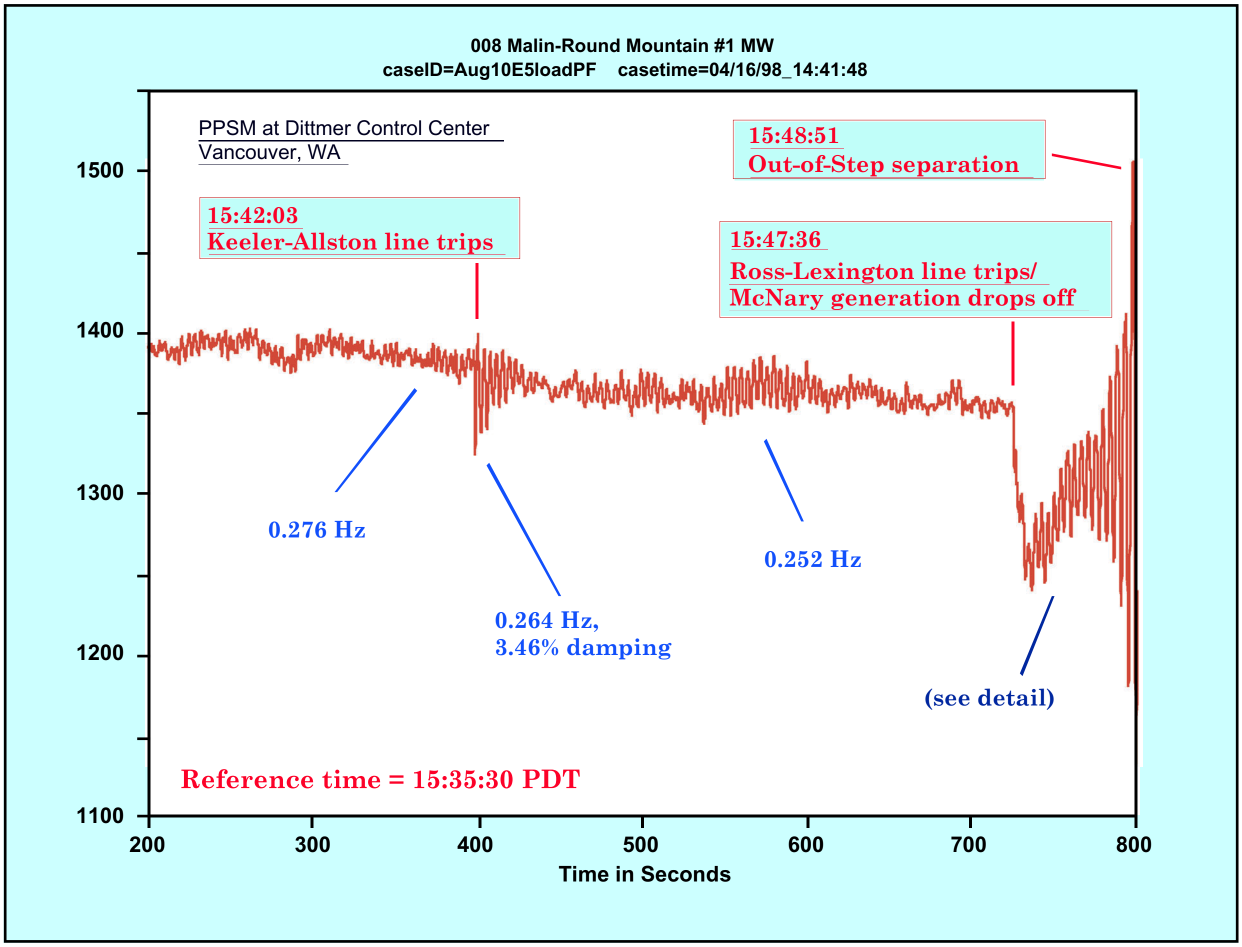
innovative device configurations and materials) to super-conducting equipment to large-scale devices for routing grid power flow. High-voltage direct current (HVDC) and FACTS technologies appear especially attractive for flow control. Effectively deployed and operated, such technologies can be of great value in extending grid capabilities and minimizing the need for construction of new transmission.

The strategic imperative, however, is to develop better information resources for all aspects of grid management—planning, development, and operation. Technologies such as large-scale FACTS generally require the support of a wide-area measurement system (WAMS), which currently exists only as a prototype. Without a WAMS, a FACTS or any major control system technology cannot be adjusted to deliver its full value and, in extreme cases, may interact adversely with other equipment. FACTS technology can provide transmission “muscle” but not necessarily the “intelligence” for applying it.

An example of the information that a WAMS can provide is shown in Figure 4. Review of data collected on the Bonneville Power Administration (BPA) WAMS system following a grid disturbance on August 10, 1996, suggests that the information that system behavior was abnormal and that the power system was unusually vulnerable was buried within the measurements streaming into and stored at the control center. Had better tools been available at the time, this information might have given system operators approximately six minutes’ warning of the event that triggered the system breakup (PNNL 1999).

Better information is key to better grid management decisions. The next subsection addresses the kinds of information gaps in current grid management.

Figure 4. Possible warning signs of the Western Systems breakup of August 10, 1996 – an example of information available from WAMS



Information Gaps in Grid Management

As the grid is operated closer to safe limits, knowing exactly where those limits are and how much operating margin remains becomes increasingly important. Both limits and margins must be estimated through computer modeling and combined with operating experience that the models might not and often cannot reflect.

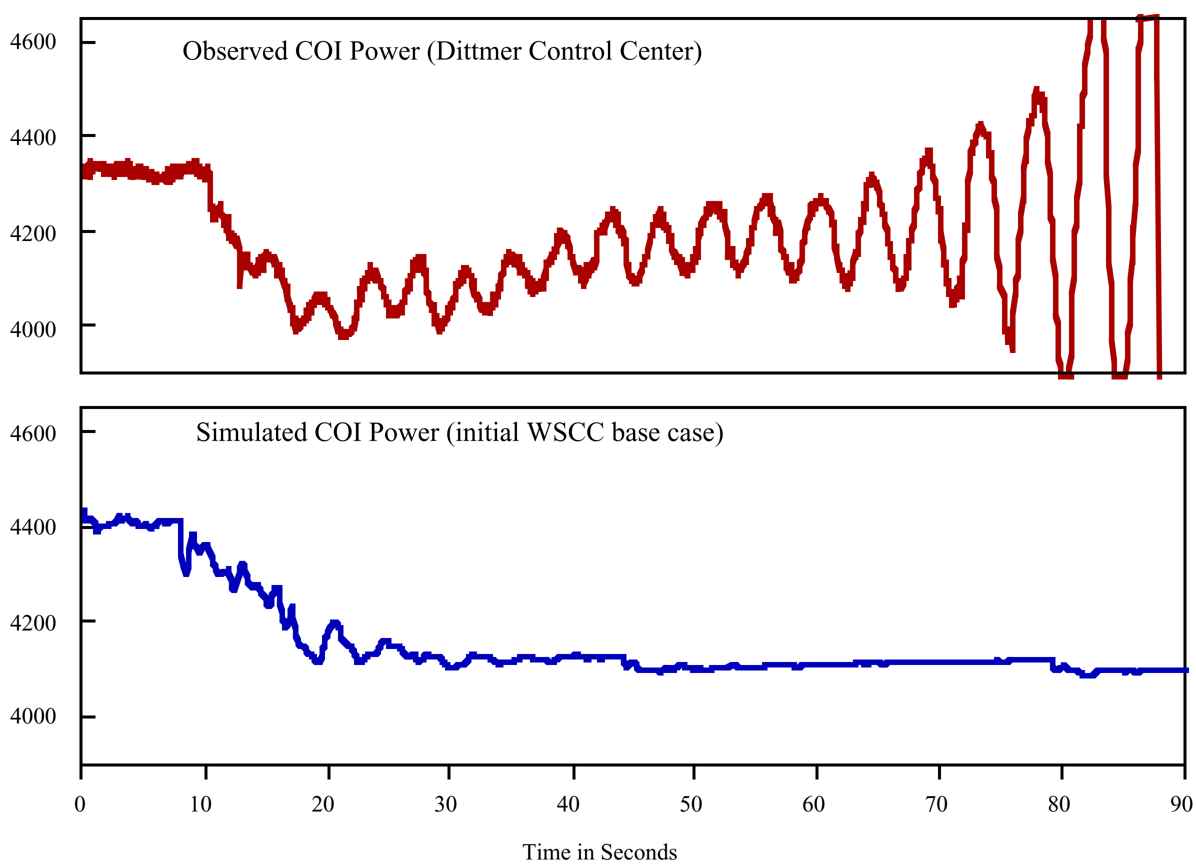
The "edge" of safe operation is defined by numerous aspects of system behavior and is strongly dependent on system operating conditions. Some of these conditions are not well known to system operators, and even those that are known may change abruptly. Important conditions include network loading, operating status and behavior of critical transmission elements, behavior of electrical loads, operating status and behavior of major control systems, and interactions between the grid and the generators connected to it. Full performance of the transmission grid requires that generators provide adequate voltage support plus a variety of dynamic support functions that maintain power quality during normal conditions and assist the system during disturbances.

All of these conditions have become more difficult to anticipate, model, and measure directly. Industry restructuring has exacerbated these difficulties by requiring that transmission facilities be managed with a minimum of information concerning generation assets. To borrow a phrase from EPRI (2001), this is one of many areas where there is a "critical interactive role" between "technology and policy."

Many cases in recent years have revealed that the "edge" of safe grid operation is much closer than planning models had suggested. The Western System breakups of 1996 are especially notable in this respect (see Figure 5), but there have been less conspicuous warnings before and since (PNNL 1999). Uncertainties regarding actual system capability is a known problem of long-standing, and it has counterparts throughout the NTG.

Developing and maintaining realistic models for power system behavior is technically and institutionally difficult, and it requires higher-level planning technology than has previously been available. An infusion of enhanced planning technology—plus knowledgeable staff to mentor its development and use—is necessary to support timely, appropriate, and cost effective responses to system needs. Better planning resources are the key to better operation of existing facilities, to timely anticipation of system problems, and to full realization of the value offered by technology enhancements at all levels of the power system.

Figure 5. Modeling failure for Western System breakup of August 10, 1996. (MW on California-Oregon Interconnection)



Challenges and Opportunities in Network Control

As noted earlier, the existing AC transmission system cannot be directly controlled; electric flow spreads through the network as dictated by the impedance of the system components. For a given set of generator voltages and system loads, the power-flow pattern in an electrical network is determined by network parameters. Control of network parameters in an AC system is usually quite limited, so scheduling of generators is the primary means for adjusting power flow for best use of network capacity. When generator scheduling fails, the only alternative is load control, either through voltage reductions or suspension of service. Load control can be necessary even when some lines are not loaded to full capacity.

A preferred solution would be a higher degree of control over power flow than is currently possible, which would, permit more effective use of transmission resources. Conventional devices for power-flow control include series capacitors to reduce line impedance, phase shifters, and fixed shunt devices that are attached to the ends of a line to adjust voltages. All of these devices employ mechanical switches, which are relatively inexpensive and proven but also slow to operate and vulnerable to wear, which means that it is not desirable to operate them frequently and/or use a wide range of settings; in short, mechanically switched devices are not very flexible controllers. Nonetheless, they are still the primary means used for stepped control of high power flows.

HVDC transmission equipment offers a much greater degree of control. If the support of the surrounding AC system is sufficient, the power flowing on an HVDC line can be controlled accurately and rapidly by means of signals applied to the converter equipment that changes AC power to DC and then back to AC. In special conditions, HVDC control may also be used to modify AC voltages at one or more converters. This flexibility derives from the use of solid-state electronic switches, which are usually thyristors or gate turn-off (GTO) devices.

Although HVDC control can influence overall power flow, it can rarely provide full control of the power flowing on particular AC transmission lines. However, conventional power-flow controllers that are upgraded to use electronic rather than mechanical switches can achieve this control. This upgrade opens the way to a broad and growing class of new controller technology known as FACTS. Many engineers regard HVDC technology as a subset of FACTS technology.

Increasingly, load itself is becoming a fast-acting transmission control device. Some degree of load control has been available for decades through interruptible rates, time-of-day rates, and demand-side management programs. A new possibility is use of real-time price feedback to loads in order to rapidly tailor the flow of power on the transmission grid, perhaps encouraging demand in one location while inhibiting it elsewhere. Advances in communication that can rapidly convey changing electricity prices to industrial and commercial users facilitate this control.

Short-term energy storage can aid in power flow control. Recent work shows that even a small amount of storage can significantly enhance the performance of some FACTS devices, and past research has shown that controllable storage devices have many applications in control of power quality and system dynamics (De Steese and Dagle 1997). These applications are addressed in later sections of this paper.

It should be noted that FACTS technology is still not entirely mature even though it is based on concepts that are two decades old. As has been the case with several other promising technologies, FACTS has not been utilized by the electricity industry at the rate that its apparent technical merits would justify. A number of lessons can be drawn from this. One is that innovative technologies compete against technologies that are already in place and are better understood. Many utilities view FACTS as not cost effective because of their high installation price; traditional, passive AC devices are perceived to have a cost advantage. Furthermore, though controller-based options for grid reinforcement are attractive, they are not well understood, and operating experience with another innovative technology, HVDC systems, suggests that use of new control devices may result in significant and unforeseen interactions with other equipment. Although these problems can be largely addressed with WAMS, their costs are unclear, and the consequences of controller malfunctions can be very serious. Some legal opinion holds that the liabilities from such malfunctions will be substantially greater than those faced by utilities before industry restructuring (Fleishman 1997, Roman 1999). Such considerations weigh on the side of grid reinforcement through less technically demanding means even though the return on investment may also be smaller.

Very few utilities are in a position to break this impasse as the management functions for which high-level technologies like FACTS are of primary relevance are passing from the utilities to a newly evolving infrastructure based upon Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), and other entities. This transition is far from complete in most areas of the U.S., and as yet there is no "design template" for the nature and the technology needs of this new infrastructure.

The Evolving Infrastructure for Transmission Management

The movement of operation and planning responsibilities from their place in the vertically integrated utility structure to the evolving new and restructured organizations has greatly weakened the essential dialogue between technology developers and users. Although this paper focuses on advanced transmission technologies, these technologies cannot be adequately discussed outside the context of the institutional framework within which they will be used. Development of advanced technology must be closely linked to its actual deployment for operational use. Together, these activities should reflect, serve, and keep pace with the evolving infrastructure needs of transmission organizations. Frameworks that discourage technology deployment will eventually inhibit its development. Unfortunately, the current uncertainty has produced exactly this effect.

To simplify our discussion, we assume that primary responsibility for grid management is assigned to an RTO. The following unknowns are of special concern:

- definition of RTO functions and resources,
- relationship between RTO and control areas,
- access to and sharing of operational information, and
- timeline for deployment of the supporting infrastructure for RTO operations.

Uncertainties about the evolving institutional framework for transmission management impede timely development and deployment of requisite technology. Key unknowns include:

- what functionalities require technical support and where they will be located within the overall infrastructure;
- what level of technological sophistication can be rationalized, accommodated, and supported at specific locations within the grid management infrastructure;
- how to accommodate the risks associated with operational use of prototypes;
- what extensions or refinements may be needed before particular technologies can provide full value in power system environments; and
- what the role will be of the RTO and other grid management entities in the overall R&D infrastructure serving power transmission needs.

Resolving these uncertainties in a timely manner may require that national energy policy address the infrastructure of transmission management. For the immediate future, the best course may be for policy makers to seek counsel from entities that are still involved in higher levels of grid management.

Performance Challenges to a New Generation of Transmission Technology

Many technologies, some surprising, are applicable to large power systems. Some hardware whose application to power systems may not be obvious at first include: acoustical radar to locate buried objects, radiation sensors to detect incipient failure in connectors or insulators, robotic vehicles (including unmanned aircraft) to examine the condition of transmission lines, specialized devices to mitigate the waveform pollution associated with some lighting technologies, the NASA Advanced Composition Explorer satellite (located more than one million miles from earth) to provide early warning of geomagnetic storms, and intruder alarms at unmanned facilities. Life sciences applications include study of: the biological effects of electromagnetic fields, the environmental impacts of a proposed transmission line on forest cover and wildlife, the function of naturally occurring microbes that can safely digest toxic spills, and the social/biological factors involved in management of large river systems. We can add to this a vast array of applications in materials science, advanced hardware and fuels, information systems, mathematical modeling and analysis, process automation, risk management, and decision support systems.

This paper's purpose is not to inventory the possible technology options. Recent studies by EPRI (EPRI 1997, EPRI 2001) present massive inventories with projections of likely merits, and a long series of DOE studies examines the subject from the perspective of national needs (DOE 1980-2000). The opportunities have not changed much in a decade, but the needs have become much more acute.

The subsections below list the strategic challenges that can be addressed through enhanced technology. Each challenge is stated as a functionality that will improve the overall performance of the NTG. Candidate technologies to meet each challenge are briefly discussed, and their current state of development is noted. An extensive, partial listing of new equipment technologies that could be applied to the NTG is given in Appendix A.

Technology Challenge #1: Broader Coordination of Grid Management

DOE's National Power Grid Study of 1980 notes that "Coordinated power system planning, development and operation results in reduction in fixed costs, reduction in operating costs, lower risks, and better utilization of natural resources." The report also lists impediments to full realization. The issues raised then have been rearticulated many times since; they are persistent, basic forces in the development of large power systems.

What has changed is the context within which these forces operate. There is now an artificial information barrier between generation and transmission, and coordination across that barrier is indirect (e.g., based upon market signals). However, direct coordination across broad geographical areas has become much more feasible from a technical standpoint and is directly consistent with the objectives of industry restructuring and the effective functioning of the national transmission grid.

A recent Federal Energy Regulatory Commission (FERC) directive assigning ultimate responsibility for grid management to a few "mega-RTOs" is a step toward the institutional framework needed for truly wide area management of the NTG. Although the details of this framework are still to be worked out, information technologies will be key to the infrastructure. Integrated computer models must quickly and accurately support power-flow calculation, risk assessment, and emergency management across broad areas of North America where such activities are now performed piecemeal. Modeling studies must be reinforced by measured information, which is also needed to assure the validity of the models. Great volumes of operational data must be integrated and sifted for indications of hidden problems or to facilitate general grid management decisions. High capacity data links are needed among control centers and RTOs. High capacity information links of a different kind are needed to achieve "virtual work team" collaboration among supporting staff who may be located at widely separated locations and institutions. All of these improvements must be made with close attention to the overall security of the information process and facilities.

One approach to real-time operational system data would be to continue the current utility strategy of treating practically all such data as proprietary. Currently, only a small group of (often overworked) utility employees has access to system operational data. Although the reasons that utilities would like to keep the details of their operations hidden from public scrutiny are clear, a significant lesson from the recent electricity crisis in California is that when the grid fails, the public pays the price. Furthermore, the shared nature of the transmission grid and the fact that problems in one area can rapidly propagate throughout the entire grid make the electricity industry unique. The data that are public by federal mandate, such as FERC Form 715 filings, are helpful, but errors, such as base-case-limit violations, restrict the usefulness of these data. The release of highly processed information, such as the posting of available transmission capacity (ATC) or Locational Marginal Price (LMP) data on the Open Access Same-Time Information System (OASIS), is also helpful, but the calculations are impossible to verify or extend if the raw source data are not available.

An alternative approach would be public posting of near-real-time operational data. FERC did not prohibit access by generators to transmission data; rather, it required that such access be non-discriminatory. Freeing the data might free the industry's entrepreneurial spirit. As a result of restructuring, the number of players interested in knowing the operational state of the grid has skyrocketed from a handful of vertically integrated utilities to hundreds of marketers, independent generators, regulators, and consultants. Currently, generation companies are making investment decisions about new plants, which cost hundreds of millions of dollars, based on very limited information about actual grid operation. This situation is almost guaranteed to produce some disastrous choices. New transmission lines may be needed, but how can governmental agencies and the public make informed decisions when information about actual grid operation is unavailable? New transmission technologies are being developed, but how can their manufacturers make informed business decisions about which technologies to pursue when they have limited means to determine need?

If data were available, third parties might quickly develop innovative informational products to meet the industry's needs. Third parties interested in selling to a market much larger than the traditional utility EMS market could develop many of the tool sets needed for analyzing large RTOs. Even with the limited data available today, third parties are offering some innovative grid analysis and visualization products. Increased availability of data might also allow for more effective independent oversight of grid operation. Currently, there is little oversight. Federal and state regulatory agencies do not have the tools or the data to effectively oversee grid activities, and because there is no access to these data, there is little incentive for third parties to develop the requisite tools.

Useful data might include transmission device status information, real and reactive power flows for transmission facilities, voltages and frequencies at key points within the transmission network, along with more processed data such as ATC and LMP information. Given the current low cost of computer storage and the availability of high-speed data communication, dissemination of these data should be simple. For example, the posting of hourly snapshots of 5,000 flow values and 2,000 status values would require less than one megabyte of storage per day. Immediate public release of some data, such as generator offers, would not be appropriate.

As a result of increased concern about possible terrorist activity, public access to transmission system information has actually become substantially more restricted. For example, on October 11, 2001 FERC restricted public access to a substantial amount of energy facility data, including the FERC Form 715 data. This is unfortunate and, for the most part, unnecessary. Public access to a large amount of additional information is possible without jeopardizing either the physical security of the transmission system or legitimate proprietary concerns of grid participants. Without such data it will become increasingly difficult for market participants to effectively utilize the NTG. As a minimum, there is a need for an industry-wide discussion on what data can legitimately be made public and what data must remain proprietary, and on the best mechanism for the release of this data.

Regardless of whether data remain proprietary within RTOs or enter the public domain, key technologies for broad data coordination are digital communications, high-performance computing, computer mathematics, data management and mining, collaboration networks, information security, and operations analysis. Discussion of these subjects and partial templates for the needed R&D can be found in reports issued by the DOE and EPRI as part of the ongoing WAMS effort (DOE 1999). Much R&D for data coordination would draw upon and directly reinforce the evolving Reliability Information Network by which Regional Security Coordinators share grid information in near real time.

Technology Challenge #2: Knowing the Limits of Safe Operation

Full use of transmission capacity means that the system will be loaded close to the "edge" of safe operation. In recent years, many cases have revealed this edge to be much closer than had been expected. Less dramatic yet of equal or greater importance are the many undocumented situations in which grid capacity has been significantly underutilized because lack of knowledge about real system limits resulted in overly conservative operation. Safe operating limits are defined by a multiplicity of system conditions that have become more difficult to anticipate, model, and measure directly.

Electrical conditions on the transmission system may not be fully known, and even if they were, their full implications might not be. It is not possible to anticipate and study all possible conditions, and the computer models used in studies are sometimes sufficiently unrealistic that they produce misleading results. Partial remedies would be to augment modeling results with measured data and to calibrate models against observed system behavior.

The challenge here is partly technical and partly institutional. On the technical side, the determination of safe operating ranges requires a variety of different inputs that are associated with a variety of different time frames, all of which are dependent on the accuracy of the underlying models and of the data provided to those models. The longest planning time frame is associated with operational limits set by planners weeks or months ahead. These usually include transient stability limitations, oscillatory stability limitations, and voltage stability limitations and are conditional on long-term forecasts of customer demand and overall power system resources. Because assumed conditions are seldom the same as actual operating conditions, the limits are intended to be sufficiently conservative that modest differences between predicted and actual operating conditions can be accommodated through later planning adjustments. These adjustments take place in a shorter time frame that supports planning for several hours to several days in advance. This shorter time frame permits more precise forecasts of pending system conditions, but it restricts the opportunity for in-depth analysis and the range of operational alternatives that can be considered. The planning and decision tools used in this time frame, though sometimes ad hoc, often provide market-critical information such as ATC to be communicated to market participants via the OASIS. Finally, in near-real time, system operators use the EMS to observe and assess the actual status of the power system. On-line tools, such as real-time power flow and contingency analysis, provide guidance for managing situations in which real-time conditions are substantially different from what was planned.

Ideally, the planning process insures that maximum transmission capability is available to the power market while system reliability is maintained. The challenge is that errors may arise at any point in the process. One problem, as noted above, is that the electrical conditions and their implications may not be fully known. The system must be observed in such a way that system operators receive timely and complete information. Complicating observation of the system is what is known as the issue of "seams" between areas of the grid. Currently in the U.S. there are approximately 140 different utility control areas and 20 higher-level security coordinators, each trying to monitor its portion of the grid. As EPRI (2001) notes, "each control entity is like its own sovereign nation as far as market and data practices go, and coordinating power transfers that extend beyond the borders of an entity entails complex technical tradeoff analyses consistent with how the grid actually responds to inter-regional power flows." Power flows easily between control areas, and, as illustrated by the example in Figure 3, the transactions and control actions in one or two areas can have grid-wide implications.

Another source of error in the planning process is that assumed conditions may differ widely from real-time conditions. If the planning limits are too high, or if some market-driven transfers become too heavy, the system may be in danger of widespread, cascading outages. In these circumstances, some market activities would have to be curtailed through actions such as TLR (transmission loading relief). Alternatively, planning limits may be too low or ATC results too conservative. In these cases, the transmission grid may be underutilized, with the market sending erroneous signals to adjust more generation or transmission than needed. One example is transmission line thermal limits, which in many markets are the limiting constraints on ATC. The amount of power that can be transferred along a line is highly dependent on ambient weather conditions. Yet fixed limits are used in most cases (sometimes these limits differ in winter and summer). Better estimation of these limits, perhaps coupled with real-time measurement of conductor temperature or sag, could result in a significant increase in ATC. The seams issue arises here as well because each security coordinator is simultaneously performing studies to determine transmission capability, usually without detailed knowledge of what its neighbors are doing.

A third source of error is flawed conceptual formulation of the models that are used to predict power system behavior under highly stressed conditions. A common theme in the post-mortem analyses of major system disturbances is that the models did not correctly predict or replicate actual system behavior. One recent example is the near-voltage-collapse in the Pennsylvania-New Jersey- Maryland connection (PJM) during July 1999 (DOE 2000). Effective intervention by PJM operators averted a loss of load, in large part as a result of EMS technology that afforded unusually good real-time observation of grid voltages. Later analysis revealed substantial optimism in the assumed capabilities of many PJM generators to support system voltages (through reactive power generation) while producing specific levels of real power (megawatts). These findings parallel utility experience around the world: the actual capability and behavior of a thermal power plant may be radically different from that indicated by generator models or nameplates. This seems especially true of gas-fired turbines, which constitute almost all new plant construction. (It has been reported that some operators outside the U.S. take their plants to maximum output every hour, just to establish capability limits.) The emerging picture is that reserve generation capability for emergency use is much smaller than previously believed, and that financial considerations may encourage plant operations changes that compound the problem in ways that system planners are just now starting to recognize. This is one of several issues that the U.S. Department of Energy (DOE) has been monitoring through its Transmission Reliability Program.

A related issue associated with the NTG study is the need for better computer modeling of the interrelationships between electricity markets and the NTG. An accurate assessment of the cost impact of the NTG bottlenecks on market operation requires detailed, time-varying analysis (e.g., hour by hour) of an entire interconnected system. Since in some portions of the NTG the constraints are due to reactive/voltage problems, traditional, linear transportation-based models are not adequate. Such analysis could prove crucial to determining the optimal locations for expanded transmission capacity. Previously, such detailed analysis had been computationally prohibitive. However, faster computer processors and greater availability of parallel processing are rapidly removing these barriers. Development of the necessary computer models and algorithms for this analysis has also been hindered by lack of availability of the interconnect-wide data needed to perform such an analysis.

From a technical viewpoint, the immediate solution is to continue the incremental changes that have been taking place. These include developing enhanced real-time systems for measurement-based information, improved tools for system analysis and visualization, improved data communication between control centers and security coordinators, increased utilization of improved computer technology to move system limit calculations closer to real time, and increased feedback of system operational data to system planners to improve the calibration of models against observed system behavior. There is a significant need to improve our understanding of the fundamental behavior of the power system and the conditions or events that lead to system failure. Improved models are an essential element of this effort. Proactive federal involvement in the development of interconnect-wide models and tools could be quite helpful.

The solutions noted above neglect relevant institutional issues. Simply stated, in most markets there is a fundamental dichotomy between the commercial participants and the transmission managers who make the market possible. Unlike the commercial participants, the managers have no clear "pay for performance" mechanism for recovering their financial investments. The absence of such a mechanism has fostered a spiraling decline in staffing, priority, and overall resources given to system planning. Calibration of planning models and direct assessment of power system behavior should be integral to the planning process. The industry has a growing wealth of data to support this conclusion, not only from its EMS facilities but also from a host of sources including integrated phasor measurement systems and substation-based data recorders. Unfortunately, most of the utility staff with access to these data are too burdened by day-to-day tasks to use the data or the tools required to analyze the data. Repeated staff reductions have meant that this complex task has almost vanished from utility organizational charts. As highlighted in EPRI (2001), the linkages among markets, technology, and policy are fundamental and must be understood and adjusted to best effect.

Key technologies for this understanding are essentially the same as those noted for Technology Challenge #1. Special requirements include mathematical systems theory, signal analysis, operations analysis, and probabilistic methodology.

Technology Challenge #3: Extending the Controllability of Network Flow

A higher degree of power flow control than is currently possible is a very attractive means to improve utilization of transmission resources. Conventional power-flow control devices include series capacitors to reduce line impedance, phase shifters, and shunt devices that are attached to the ends of a line to adjust voltages. A far higher degree of control is provided by HVDC transmission equipment and FACTS technology. The so-called NGH (a device, in which power electronics facilitate safe application of a conventional series capacitor) appears to be a precursor to FACTS technology.

Devices that improve flow control can be used individually or in combination to directly regulate power routing on the grid and to relieve dynamic problems that may limit grid utilization. Control of this sort is a very attractive alternative to the construction of new or stronger lines. This is not the whole story, however, because power system controls are subject to errors in the control law on which they are based or the models from which the control law is developed. (This is in contrast to the functional reliability of a new transmission line or power plant, which is almost synonymous with its hardware reliability.) Because of this vulnerability, the overall reliability of large-scale control systems cannot be assessed or assured by the straightforward and proven methods that are used in construction-based reinforcements to the grid. How, then, should the choice be made between controls and construction of new transmission capacity?

A full demonstration of controller reliability is rarely possible. It is always necessary to trade controller benefits against the risks associated with closing a high-power control loop around system dynamics that are not fully observed and not fully understood. Controller reliability must be assessed broadly, incorporating engineering judgment and sound practice. Uncertainty should be mitigated where possible, but this is often a slow and technically difficult process (Hauer & Hunt 1996). Whatever uncertainty cannot be mitigated should be accommodated in controller design and operation. All of these measures require that wide-area control systems be supported by wide-area information systems, and that the grid management infrastructure include an appropriate degree of technical expertise in control engineering (Hauer & Taylor 1998).

Wide-area control, whether using FACTS or less advanced technologies, offers many benefits to the next-generation national transmission grid. A recent FACTS installation in Brazil is especially noteworthy; it links two regional systems with an AC line plus two thyristor-controlled series capacitor (TCSC) units. Prior to this, a DC line would have been the inevitable and more expensive choice.

Here in the U.S., the installation by the New York Power Authority of a Convertible Static Compensator (CSC) FACTS device has increased the power transfers on the Utica-Albany power corridor by 60 MW in its initial phase, with a projected increase to 240 MW when Phase Two is completed in 2002. However, it is important to place these numbers in context. Overall, the peak electricity demand in New York State is approximately 30,000 MW, with approximately half the demand in upstate New York and the remainder in New York City and Long Island. The current import capability from the upstate region to the city and Long Island is approximately 4,500 MW, with another 2,000 MW coming from PJM. Therefore, the increase from the CSC device is approximately five percent of the current capacity, and about 1.5% of the peak New York City/Long Island load.

A proposal that complements the use of FACTS devices to achieve better network control is to break up the current Eastern and Western Interconnections into smaller, more manageable synchronous interconnections. These smaller interconnections (which could correspond to existing regional reliability councils) would be joined by HVDC ties; the size of the ties would match existing transmission transfer capabilities (De Steese and Dagle 1997). The use of HVDC between the interconnections would permit complete control of power flows between interconnections, completely eliminating long-distance loop flow. Loop flow would still be an issue within the interconnections, but their smaller size would make this flow easier to manage. Of course, such wide-scale dismantling of the Eastern and Western Interconnections would require major investment in new HVDC lines and could present a host of new, unforeseen technical problems.

A key challenge to the use of advanced technology to achieve better network control is that it is a "high tech" option entering the business environment for utilities, ISOs, and other grid managers, which today favors "low tech" investments. Advanced control technology is often characterized by high initial costs and ongoing maintenance and operation costs. In addition, use of HVDC or FACTS devices can result in higher power losses, with typical converter losses of one or two percent of flow. For most utilities, cost-benefit analysis currently favors doing nothing, letting new generation take care of the need, or investing in familiar passive AC devices. Outstanding issues to be addressed before advanced technologies can compete in such an environment include the need for operational experience, quantification of benefits, and resolution of impediments to reliable control in high-performance applications.

High-performance hardware for wide-area control is ready for use; conventional technologies have served local and regional needs for many years. Full use of wide-area control demands an improved infrastructure for wide-area information. WAMS, the information counterpart to FACTS control, is expressly designed to provide this infrastructure.

Technology Challenge #4: Dealing with Operational Uncertainty

Providing reliable and economical electric power calls for two parallel efforts related to uncertainty. The first is to reduce uncertainty by means of information that is better and more timely than what is currently available. The second is to accommodate the residual uncertainty through the use of appropriate decision tools.

In 1996, two massive breakups of the western power system demonstrated the need for improved resources to deal with the unexpected. As noted above, data collected in real time at BPA's Dittmer control center contained subtle but definite indications of oscillatory instability for several minutes prior to the actual breakup on August 10. BPA operators also reported that hints of weak voltage support may have been present for much longer. Had there been means for converting these hints to unambiguous operator alerts, that breakup might have been avoided entirely.

Contradicting actual system behavior, later studies performed with standard WSCC models (adjusted to the conditions and events leading to the breakup) indicated that the system had excellent dynamic stability. Enhanced models, internally adjusted to match observed system behavior, are outwardly more realistic but still suspect. Modeling errors are one of many uncertainties that improved resources for grid management must accommodate.

Even if suitable planning models had been available, operating conditions preceding the August 10 breakup were far from nominal and had not been examined in system reliability studies. These studies are generally performed weeks to months in advance, and planners cannot anticipate all combinations of seemingly minor outages that may be part of the operation of a large power system. Planning uncertainty and its attendant risks can be mitigated in part if system capacity studies are performed with a much shorter forecasting horizon and based on reasonable extrapolations of current operating conditions. This approach calls for much broader real-time access to those conditions than any one regional control center now provides. The requisite computer tools are directly consistent with the framework envisioned for dynamic security assessment (DSA), however. This is also true of the measurement-based operator alerts mentioned earlier although the mathematics needed is quite different.

The combinatorial problem for longer-term planning remains especially formidable. The number of likely contingency patterns, already huge, is becoming even larger as the market seeks energy transactions across longer distances. Future practices may also represent model errors as contingencies. Even without this change, direct examination of each individual contingency pattern is not feasible. Contingency evaluation is a further challenge. Never a simple matter, it must now reflect new linkages between system reliability and market economics. Decisions must be rendered more rapidly than before despite increased uncertainty and sometimes increased risk.

Reducing and accommodating these uncertainties requires a broad, multi-faceted effort. Requisite technologies include:

- Improved real-time tools to examine power system signals for warnings of dangerous behavior. The more rapidly that operator intervention is initiated, the more likely that a blackout can be averted.
- Improved visualization, giving operators a bird's-eye view of the power system.
- Mathematical criteria, tools, and procedures for reducing and/or characterizing errors in power system models.
- Characterizations and probabilistic models for uncertainties in power-system resources and operating conditions.
- Probabilistic models, tools, and methodologies for collective examination of contingencies that are now considered individually.
- Cost models for quantifying the overall impact of contingencies and ranking them accordingly. It is essential that these models be realistic and suitable for use as standards for planning and operation of the overall transmission grid.
- Risk management tools, based on the above probabilistic models of contingencies and their costs, that "optimize" use of the electricity system while maintaining requisite levels of reliability.

Development of the technology noted above can likely be expedited through technology transfers from outside the power industry. Even so, there are special and difficult problems. The knowledge base for actual power system behavior, required both to define the subject technologies and obtain best value from their use, is not well evolved. The knowledge base and the technologies should develop together, in or close to a practical utility environment.

Furthermore, probabilistic planning is not just a smooth extrapolation of current practices. It requires new skills and practices. These practices must be developed, evaluated against those now in use, and then approved for use at the RTO level. These matters should be addressed at the earliest possible stage of technology development.

Technology Challenge #5: A Grid that Heals Itself

The interconnection of large power systems into still larger ones greatly increases the possibilities for widespread failure. Grid managers go to great lengths to anticipate and avoid such failure. However, at some level of complexity, anticipation and avoidance become too difficult or expensive.

A variety of lessons can be extracted from the 1996 breakups of the western power system. One of these lessons is that when prevention of system breakups becomes impractical, it is time to focus on minimizing the consequences. A triage approach has long been characteristic of grid operations; the operation of individual relays is a good example of removal of a small portion of the system to save the whole. On a broader basis, the use of under-frequency load shedding has been a very effective means of saving the grid from frequency decay at a cost of perhaps five or 10 percent of total load. Limited self-healing is also found in the use of automatic circuit-break reclosing after events such as the loss of a line from a lightning strike.

What is new since 1996 is a shift in emphasis from aggressive use of preventive control, accepting possible loss of some load, to consideration of "dynamic islanding" strategies that accommodate an occasional breakup while minimizing its impacts and assuring smooth restoration of electricity services. Dynamic islanding would involve:

- Emergency, possibly localized, controls that separate the power system into either predefined islands or dynamically defined islands as dictated by conditions that are sensed locally.
- Islanding options designed for minimal loss of service, given proper control assistance.
- Islanding and restoration as a continuous smooth process controlled by FACTS, HVDC, or automatic generation control.
- Conversion of some AC lines to DC. This change is particularly attractive for lines that would otherwise become stranded assets under the pressure of new generation installed close to major loads.

Avoiding just one catastrophic event would likely payback much of the investment cost of FACTS technology and the associated infrastructure. But there are both technical and institutional concerns. From a technical point of view, developing even limited islanding capability, let alone grid self-healing, is an immense challenge. During islanding, the two new islands will be simultaneously presented with a combination of potentially large initial generation/load imbalances and changes in line flows as existing tie flows are eliminated. Frequency regulation characteristics will also change due to the changes in total inertia. Although a dynamic islanding scheme has been implemented on the WSCC system, its use on the Eastern system would be much more involved because of the higher density of tie lines. From an institutional point of view, incentives would be needed to encourage the development of islanding schemes. It appears that only an ISO or RTO would in a strong business position to assume the costs given the geographical area involved.

Technology Challenge #6: More Power in Less Space

There are many reasons to seek power system equipment that requires a minimum of space. New rights of way for transmission lines are environmentally intrusive, difficult to route, and subject to a very slow approval process as local authorities are increasingly reluctant to approve projects that do not address local need. These problems tend to be less severe for underground transmission cables, but new routes or added space for underground cables may be impossible in highly urbanized environments like Chicago or New York City; costs inhibit the use of underground cables in less urban areas. Substations, generators, and transformers all benefit from having a smaller "footprint," especially if the equipment itself is smaller and more portable.

So how can we fit more power into a given space, or into even less space? Conventional solutions include “reconductoring” lines to carry more current at the same voltage, revising lines to operate at higher voltage (if possible), and converting AC lines to DC. The use of composite materials is a promising approach for reconductoring. Traditionally, overhead transmission lines have been constructed using aluminum conductors steel reinforced (ACSR) consisting of stranded aluminum about a stranded steel core. The aluminum carries the current, and the steel provides mechanical support. The limiting constraint for such lines is sag resulting from heating. A new approach for increasing conductor current capacity without increasing weight is to replace the steel core with a composite material, such as glass-fiber. Because the tensile strength of the glass is up to 250 percent of the strength of steel, the composite conductors are lighter and stronger and could have higher current capacity. Reduction in sag allows tighter spacing of conductors, which reduces magnetic fields and might mean that new conductors could be added in existing rights of way.

A complementary approach to increasing the available capacity of existing AC lines is to dynamically determine the actual conductor limits. The thermal capacity of an overhead line is highly dependent on ambient conditions; there is more power-transfer capacity when the line is being operated in cold, windy conditions than when it is operating in hot, calm weather. Approaches to dynamically determining conductor limits include either direct measure of conductor temperatures or use of a differential global positioning system (GPS) to directly measure the sag of critical spans.

For higher-voltage lines, limits are usually based on “loadability” constraints rather than thermal limits. The loadability of a line that cannot be operated close to its thermal limit can often be improved by compensating devices or full FACTS control. Another promising though relatively conventional technology is compact transmission lines that are reconfigured to carry more power (at the expense of increased losses).

An alternative to overhead lines is buried cables. Several different cable designs can be used; oil-impregnated paper-insulated pipes are the most common. A key advantage of underground cables is that they usually face little public opposition. Also, the closer spacing of the conductors results in greatly reduced electromagnetic fields (EMFs) because of phase cancellation. Finally, underground cables are not subject to weather and thus may be more reliable than aboveground lines. The key disadvantage of buried cables is cost. With cost ratios of up to ten times for rural high-voltage lines, it is nearly always more economical to build overhead lines unless one is in an urban area. Also, the length of AC cables is limited by their relatively high capacitance; uncompensated cables may be limited to perhaps 25 miles. Finally, over the long term, underground cables may not be as reliable as overhead lines because it takes substantially longer to locate and correct problems with buried lines.

Truly strategic improvements in compactness call for new technologies like supercapacitors, transformerless HVDC, and cryogenically enhanced devices. Cryogenic operation (i.e., operation at unusually low temperatures, which may or may not be low enough to achieve superconductivity) reduces or eliminates resistance in an electrical device and thereby allows a several-fold in increase in its power-handling capacity. This benefit can be exploited either as increased capacity within given size and weight constraints or as equivalent performance in a much smaller and lighter package. However, cryogenic devices also have disadvantages. For example, some super-conducting devices operate with extremely high currents and thus radiate very intense magnetic fields. As a general rule, the introduction of cryogenic cooling adds complexity to a device, so a utility using cryogenic devices would have to hire employees with the specific skills to maintain these devices. Cryogenic devices also generally require long cool-down times, up to a week or more for some such as super-conducting magnetic energy storage (SMES) and large transformers. Certain maintenance and repair procedures may require warming the devices up to ambient temperature, which takes a similar amount of time. This characteristic may be an unacceptable operational constraint.

Cryogenic devices now include cables, transformers, current limiters, switches, generators, and energy storage devices (SMES). These devices are at stages of development ranging from working prototypes to a few commercially successful products. The underlying base technologies are the subject of active research, and the technical feasibility of cryogenics in general is increasing steadily. As with FACTS, the chief impediment to practical deployment is the initial investment.

Another partial solution to current difficulties with obtaining new rights of way is to utilize non-traditional transmission paths, such as submarine cables. One such project currently under consideration, known as the Neptune Project, seeks initially to connect 345-kV substations in Brooklyn and Long Island NY with a 345-kV substation in northern New Jersey via two 600-MW HVDC cables buried in trenches on the Atlantic Ocean floor. Subsequent phases seek to link New York City with a substation in New Brunswick, Canada using a 1,200-MW submarine HVDC; cables added later would join Boston and other New England locations. Another project under consideration seeks to link Ontario, Canada to either Ohio or Pennsylvania using several HVDC cables under Lake Erie. Given the large number of urban load centers located on the oceans or Great Lakes, the commercial success of one such submarine HVDC project could lead to many more. The advantage of such an installation is that no eminent domain authority is needed to obtain the water rights of way, and the relatively small land-based converter stations that are required can be located to bring power directly into urban load centers. Due consideration must be given to avoid harming the aquatic environment, with the cables routed to avoid active fishing and sensitive environmental areas.

Technology Challenge #7: Assessing New Technologies Using Life-Cycle Analysis

Investments in new technologies can be both necessary and dangerous. Investments in the wrong technologies can lead to disaster. Timely new ways to reduce costs and improve performance are essential to business survival. Utilities tend to be very cautious in investing in new technology.

One reason for their caution is that the actual merits of any new technology can be difficult to estimate in advance. New or advanced technologies are very likely to have hidden costs (and may also have hidden benefits). Some technologies are "fragile," requiring significant engineering design or unforeseen maintenance. Others are "intrusive" in that their use calls for major changes in associated technologies and methods. Still others produce long-term environmental problems, such as the disposal of hazardous materials used in their construction. And some technologies might fail in a catastrophic manner that endangers human health and safety.

All utilities are well aware of these possibilities, but few individual utilities have the resources to assess them. Suitable resources can be assembled on a collaborative basis, but a suitable assessment methodology must also be developed.

Full assessment of new technologies calls for a life-cycle analysis that considers all costs and all benefits, with suitable consideration of regulatory constraints and other external or uncertain factors. To be inclusive, life-cycle analysis should start with production of the technology and consider impacts upon the economy, health and safety, the natural environment, and other elements of the public good. The analysis continues from this point through all expected uses of the product to its eventual recycling or disposal by other means.

The electric power industry seldom makes equipment acquisitions using such thorough analysis. The industry will also argue, reasonably, that it cannot afford in-depth consideration of all aspects of the public good in everyday business decisions. However, the norm for much equipment procurement is to accept the minimum bid. This practice has already populated the national grid with a large amount of energy-inefficient equipment. The practice of life cycle cost optimization should at least consider the full range of tradeoffs, comparing benefits with the total cost of ownership for the life of the equipment. Life-cycle costs include acquisition costs as well as costs of capital, energy, operations, maintenance, and disposal.

Technology Challenge #8: The Intelligent Energy System

Information is the crosscutting issue in all transmission grid technology challenges. WAMS and FACTS share an underlying vision of an Intelligent Energy System (IES) in which “intelligent” planning, design, control, and operation of system assets are the primary means for meeting energy demands. An IES might well involve coordinated operation of the electrical and gas energy systems, with the gas system providing virtual storage for electrical energy. The IES would certainly draw upon FACTS technology for the routing of electrical power and upon dispersed assets such as distributed generation, energy conservation, direct or indirect load control, and renewable energy sources. WAMS is a critical element in the information infrastructure needed to make the IES possible and to insure power system reliability.

The vision of an IES extends beyond FACTS and perhaps beyond WAMS. Additional elements include protective relay systems that “adapt” to widely variable power flows, diagnostic tools to reduce human error during system maintenance, enhanced information tools for emergency management, and “intelligent” data miners that sift operating records for evidence of needed maintenance. Some specific examples, extracted from much more detailed treatments in PNNL (1999), are presented below.

Protective Controls—Relay Coordination

Containing a sizeable disturbance usually requires appropriate action by several relays. Communication among the relays is often indirect, through the power system itself. Effectively designed direct communication among relays would make coordination more reliable from the hardware perspective. Relays, like transducers and feedback controllers, are signal-processing devices that have their own dynamics and modes of failure. Some relays sense conditions (like phase imbalance or boiler pressure) that power-system planners cannot readily model. At present, there are few engineering tools for coordinating wide-area relay systems.

Large power systems are sometimes operated in ways that were not foreseen when relay settings were established. It is not at all apparent that fixed relay settings can accommodate the increasingly busy market or, even more difficult, the islanding that has been seen recently in North America. It may be that relay-based controls, like feedback controls, will need some form of parameter scheduling to cope with such variability. The required communications could be highly vulnerable from a security standpoint, however, so precautions against the growing threat of "cyber attack" would be needed.

Several recent grid events suggest that there are still questions to be resolved regarding the basic strategy or economics of bus protective systems (PNNL 1999). In the western system breakup of December 14, 1994, it appears that "bus geometry" forced an otherwise unnecessary line trip at the Borah substation in Idaho and led directly to the system breakup. Bus geometry was also a factor when all transmission to San Francisco was lost on December 8, 1998. Following routine maintenance at the San Mateo substation, a breaker was closed while protective grounds were still attached. The resulting fault tripped all lines to the San Mateo bus because a differential relay system had not been fully restored to service. An appropriate diagnostic tool would have indicated this condition and warned that the grounds had not been removed.

Emergency Management—the Northeast Ice Storm of 1998

Emergency management resources of the Northeast Power Coordinating Council were severely tested when a series of exceptionally severe ice storms struck large areas in New York, New England, Ontario, Quebec, and the Maritime provinces between January 5 and 10, 1998. The worst freezing rains ever recorded in that region deposited ice up to three inches thick. Resulting damage to transmission and distribution was severe (more than 770 towers collapsed).

The event resulted in some valuable lessons regarding system restoration. Emergency preparedness, cooperative arrangements among utilities and with civil authorities, integrated access to detailed outage information, and an innovative approach to field repairs were all found to be particularly valuable. The disturbance report mentions that information from remotely accessible, microprocessor-based fault locator relays was instrumental in quickly identifying and locating problems. Implied in the report is that the restoration strategy amounted to what mathematicians call a "stochastic game," in which some risks were taken in order to make maximum service improvements in the least time—and with imperfect information about system capability.

Technology Challenge #9: Physical and Cyber Security of the Transmission Grid

Given the recent increased awareness of the possibility of terrorist activity, it seems especially pressing to address the physical security of the NTG. (This paper focuses on the transmission system only and does not address the physical security of individual generation stations.) We consider transmission security in relation to the risk of physical destruction of system elements and concerns about cyber security.

In relation to concerns about physical destruction, the blessing and the curse of the transmission grid is its immense size. In the U.S. there are currently more than 150,000 miles of transmission lines that are 230 kV or higher, and there are many tens of thousands more miles at lower voltage levels. In both the Eastern and Western Interconnects, there are tens of thousands of individual transmission lines and many thousands of individual high-voltage transformers. The curse is that such a system is impossible to "secure;" there is no effective means to prevent a determined group of individuals from destroying a portion of the grid. But the blessing is that they could destroy only a miniscule portion. In addition, any destruction aimed of individual towers would have temporary effects. Given the regular occurrences of tornadoes, hurricanes, ice storms, and earthquakes, the transmission system has been designed to take its share of individual hits and continue to function. And the utility industry is quite adept at quickly repairing the damage done from such natural occurrences. It would be very difficult for even a large, well-organized group to duplicate the physical damage done by even a moderate ice storm.

The issue is whether a major disruption could be caused if various key grid facilities, such as electric substations or rights of way with many individual circuits, were selectively targeted. The answer is "yes" if enough key facilities were destroyed. But the impacts would likely be temporary because transmission lines could relatively quickly be rerouted around most substations. Some equipment (e.g., transformers) would be vulnerable and difficult to replace. The destruction of multiple transmission stations by a knowledgeable saboteur with a highly organized attack could result in substantial damage and long-term blackouts.

Another concern is security of information systems or cyber security. The increasing reliance of the electric power industry on communications and control systems together with the remarkable advance of electronic intrusion technologies and techniques make the restructuring utility industry particularly vulnerable to disruptions resulting from inadequate safeguards and security capabilities. More points of entry into command and control systems will become available to potentially hostile individuals or organizations. Many of these entry points will differ from the points of access previously established to serve a vertically integrated utility industry. The advent of real-time power dispatching coupled with competition in retail power markets and many other challenges of operating in a restructured industry environment will greatly reduce the safety margins currently maintained by electric utilities. The utility system of the future could become much more vulnerable to corruption by skilled electronic intrusion from both inside and outside. A primary, emerging need in the utility industry is for development of new guidelines, policies, and standards for the selection and implementation of cost-effective security measures (EPRI 1996).

The protection of critical civilian infrastructure has been a national focus since the mid-1990s with the formation of the Presidential Commission on Critical Infrastructure Protection (PCCIP) in July 1996 and the Presidential Decision Directive 63 (PDD-63) on Critical Infrastructure Protection issued in May 1998. DOE is responsible for the electric power sector and the natural gas and oil production and storage sectors and has formally designated NERC and the National Petroleum Council (NPC) as liaison organizations. In April 2001, NERC published a white paper: *Approach to Action for the Electricity Sector* that outlines the electric power industry's plans for security against physical and cyber attack.

Meeting the Technology Challenges

For lack of a clear "business case," new technology investments often involve more financial risk than any single utility (or new ISO) can accept. Motivating these investments will require some combination of definitive national policy along with market models for investment planning.

Institutional Issues

A formidable number of institutional issues hinder timely identification, development, and introduction of new technologies. Today's utilities are understandably reluctant to fund R&D that is not promptly and directly beneficial to them. Likewise, utility suppliers will not fund new transmission technology research if there is not a reasonable likelihood of an adequate return on the investment. Contrary to the premises under which EPRI was established separately from the DOE national laboratories, it is now difficult for EPRI to act as the coordinating umbrella organization for long-term R&D in the public interest. Much of the work produced by EPRI is essentially unavailable to the many nonmembers. The following "out-of-the-box" solutions should be considered:

- Apply a user fee to all institutions that engage in energy business. This fund would be used exclusively for energy R&D in the public interest, and all R&D results would be fully available to all energy business institutions.
- With suitable oversight provisions, disperse the above R&D fund through a DOE entity or a new public-service arm of EPRI (all institutions that engage in energy business would be members). It might be preferable to coordinate and consolidate these activities through a new umbrella organization for energy R&D.
- Engage industry experts in mentoring R&D and in-the-field assessments that are needed to close the gap between the development of new technology and its actual deployment for operational use.

Effective Utilization of Federal Resources

The federal government is very involved in the national grid through the federal utilities, including the TVA, the Power Marketing Administrations (PMAs), various elements of the U.S. Army Corps of Engineers and of the U.S. Bureau of Reclamation, as well as other entities. Collectively, the federal utilities operate "backbone" facilities for a large portion of the North American power system.

The federal government is also the ultimate steward for the staff skills, knowledge, and operational infrastructure of the federal utilities. These utilities are unique national resources of great value. They are immediately available to reinforce energy reliability in the public interest, a role in which they have long been a mainstay. Consideration should be given to the following ways to better utilize this resource:

- Fully engage the federal utilities as advisors and/or researchers in ongoing federal efforts to meet national energy needs.
- Draw on the federal utilities for field testing and operational assessment of new or prototype technologies. Give special attention to critical enabling technologies that have not drawn sufficient commercial interest to assure their timely evaluation and refinement.
- Identify critical resources provided by the federal utilities and integrate these resources into the national laboratory system. Support could be provided through a consortium arrangement among the national laboratories and federal utilities.
- Take immediate steps to establish a productive dialogue among all members of the proposed consortium and safely archive their collective institutional knowledge for future use.

Effective Utilization of Academic Resources

The electricity industry may be underutilizing the R&D potential of American universities. However, a contrary view holds that industry needs are primarily in development and that universities lack both the mission and staff continuity to proceed past the initial research phase. The proper relationship between university and industry has not been determined and should not be regarded as fixed. What is clear is that the dialogue between universities and the electricity industry is weaker than is the university-industry relationship in most other industries and that few universities have the direct industry involvement or the "institutional culture" that is needed for practical technology development in this area. Changing this situation might lead to a university system closer to the European model, in which many academics are part-time industry employees. Fundamental changes in the relationship between university and industry have many ramifications, and an open discussion of the matter would be timely.

One bright spot is the growing trend toward cooperative university/industry research centers. These centers seek to bridge university-industry gaps by directly involving industry in university research projects. This partnership helps projects maintain a degree of focus on problems currently facing the industry. The challenge for the universities involved in such centers is to demonstrate to their industrial members that membership fees represent money well spent.

In addition, there are growing numbers of faculty members involved in start-up companies in the power area. Universities nationwide are seeing a need to foster economic development in their local regions and states and to facilitate the transfer of university expertise and research to industry. Although a number of mechanisms exist to meet these goals, encouraging faculty with innovative ideas to form start-up companies is particularly promising as much of the country's innovation arises from entrepreneurial activity by small companies.

Advanced Technology Related Recommendations

Sustainable solutions require balances between generation, transmission, and demand; planning and operations; profit and risk; the roles of public and private institutions; and market forces and the public interest. The strategic need is not just for advanced technology in the laboratory but also for an infusion of improved technology at work in the power system. The chief impediments to this are institutional; they can be resolved through a proactive national consensus regarding institutional roles. Until this consensus is achieved, the lack of linkage between technology and policy may be a disruptive force in continued development of the national transmission grid and the broad infrastructures that it serves.

Listed below are several specific recommendations to address national transmission grid issues by creating a framework to accelerate the development and deployment of appropriate advanced technologies.

- Establish incentives for both private and public sector investment in RD&D. While federally funded basic research is important, ultimately it is the commercial sector that should move technology from the research lab to the marketplace. There is a need to accelerate the transition process within the electricity industry to reduce uncertainties regarding the future structure of generation and transmission markets since such uncertainties greatly impede investment in RD&D.

- Develop performance metrics for the national transmission grid where performance measures can be used to determine minimum planning and operational standards. These outcome-based measures would be consistent with the goals of the national transmission grid where issues such as serving the public good, promoting the economy, and ensuring national security can be balanced against the profit motivation associated with individual companies engaged in the electricity sector. Such a framework provides an incentive for private and public funding to research, develop, and deploy advanced technology because the linkage between enhanced performance associated with advanced technologies can be mapped to specific goals, with emphasis upon those technologies that cost effectively address poor performance according to these established measures.

- Apply a user fee to all institutions that engage in energy business. This fund will be used for energy R&D that is performed in the public interest, and all R&D results will be available to all institutions that engage in energy business.

- Stimulate the research, development, testing, and deployment of cost-effective technologies that allow greater capacity in existing right-of-ways. This includes passive reinforcement (e.g., advanced conductors and transmission configurations), active reinforcements (e.g., FACTS, HVDC, energy storage, and non-transmission technologies), and advanced information resources and controls that facilitate best use of transmission resources while ensuring system reliability.

- Promote programs that provide opportunities for energy consumers to manage their distributed energy resources (generation, storage, and load) in response to competitive market forces, including increased price visibility, demand-side participation in energy and ancillary services markets, and removal of technical and institutional barriers to distributed energy resources.

- Provide a forum for an industry-wide discussion to reach consensus on information access and dissemination issues. Certain information on system operations should be made broadly available to encourage markets to function, yet other information may be proprietary or sensitive.

- Establish security standards (both physical and cyber) for protecting the national transmission grid from attacks of malicious intent. Such standards should be derived from ongoing research in recognition of the evolving threat against the National critical civilian infrastructures.

- Draw upon the Federal utilities as a uniquely available and competent technical platform for inclusion in an expanded national RD&D infrastructure. Identify resources (facilities, staff, software, etc.) that do or could provide essential support to planning, development, and operation of the North America power system.

- Engage industry experts in the mentoring of R&D efforts and in the field assessments (demonstration projects) that are needed to close the gap between the development of new technology and its actual deployment for operational use. Give special attention to "critical path" enabling technologies that have not drawn sufficient commercial interest to assure their timely evaluation and refinement.

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Appendix A: List of New Technology Equipment to Reinforce the Transmission Grid

The transmission system of the future must not only have increased capacity to support the market demand for energy transactions, it must also be flexible to adapt to alterations in energy-delivery patterns. These patterns change at various time scales: hourly, daily, weekly, and seasonally. The transmission system must also adapt to delivery patterns dictated by the evolving geographical distribution of load and generation. As generation planning and dispatch decision making are placed in the hands of organizations other than utilities, new technologies that afford transmission planners a wider range of alternatives for deployment of power become more attractive.

This appendix lists some of the newer hardware technologies that are being researched and deployed to reinforce grid operations. The range of potential technologies is enormous. This appendix is limited to the hardware technologies that are most directly applicable to grid operations; the list presented is not exhaustive. Software technologies are discussed in the body of the paper and are not addressed here.

The appendix organizes hardware technologies into the following categories:

- Passive reinforcing equipment,
- Active reinforcing equipment, and
- Real-time monitoring equipment.

Within each category, we list the relevant technologies and summarize the primary objective, benefits, barriers to deployment, and commercial status of each.

Passive Reinforcing Equipment

This section discusses the potential impacts of new technologies associated with AC transmission lines and related equipment (transformers, capacitors, switch gear, etc.). This category includes the increased value (capacity per unit cost of installation, operation, and maintenance) obtained through new conductor materials and transmission line configurations as well as the flexibility gained to reconfigure the transmission system through greater modularity of transmission equipment.

Passive AC devices constitute by far the majority of the existing network. Though new lines will certainly be needed to reinforce the grid, the siting of these lines will continue to be a major challenge. Getting the most out of existing rights of way minimizes the need for new lines and rights of way and can minimize the societal concerns associated with visual pollution and high-energy EMFs.

Conductors

Advances in conductor technology fall into the areas of composite materials, and high-temperature superconductors.

High-Temperature Super-Conducting (HTSC) Technology: The conductors in HTSC devices operate at extremely low resistances. They require refrigeration (generally liquid nitrogen) to super-cool ceramic super-conducting material.

Objective: Transmit more power in existing or smaller rights of way. Used for transmission lines, transformers, reactors, capacitors, and current limiters.

Benefits: Cable occupies less space (AC transmission lines bundle three phase together; transformers and other equipment occupy smaller footprint for same level of capacity). Cables can be buried to reduce exposure to EMFs and counteract visual pollution issues. Transformers can reduce or eliminate cooling oils that, if spilled, can damage the environment. The HTSC itself can have a long lifetime, sharing the properties noted for surface cables below.

Barriers: Maintenance costs are high (refrigeration equipment is required and this demands trained technicians with new skills; the complexity of system can result in a larger number of failure scenarios than for current equipment; power surges can quench (terminate superconducting properties) equipment requiring more advanced protection schemes).

Commercial Status: A demonstration project is under way at Detroit Edison's Frisbie substation. Four-hundred-foot cables are being installed in the substation. Self-contained devices, such as current limiters, may be added to address areas where space is at a premium and to simplify cooling.

Below-Surface Cables: The state of the art in underground cables includes fluid-filled polypropylene paper laminate (PPL) and extruded dielectric polyethylene (XLPE) cables. Other approaches, such as gas-insulated transmission lines (GIL), are being researched and hold promise for future applications.

Objective: Transmit power in areas where overhead transmission is impractical or unpopular.

Benefits: The benefits compared with overhead transmission lines include protection of cable from weather, generally longer lifetimes, and reduced maintenance. These cables address environmental issues associated with EMFs and visual pollution associated with transmission lines.

Barriers: Drawbacks include costs that are five to 10 times those of overhead transmission and challenges in repairing and replacing these cables when problems arise. Nonetheless, these cables represent have made great technical advances; the typical cost ratio a decade ago was 20 to one.

Commercial Status: PPL cable technology is more mature than XLPE. EHV (extra high voltage) VAC and HVDC applications exist throughout the world. XLPE is gaining quickly and has advantages: low dielectric losses, simple maintenance, no insulating fluid to affect the environment in the event of system failure, and ever-smaller insulation thicknesses. GILs feature a relatively large-diameter tubular conductor sized for the gas insulation surrounded by a solid metal sleeve. This configuration translates to lower resistive and capacitive losses, no external EMFs, good cooling properties, and reduced total life-cycle costs compared with other types of cables. This type of transmission line is installed in segments joined with orbital welders and run through tunnels. This line is less flexible than the PPL or XLPE cables and is, thus far, experimental and significantly more expensive than those two alternatives.

Underwater application of electric cable technology has a long history. Installations are numerous between mainland Europe, Scandinavia, and Great Britain. This technology is also well suited to the electricity systems linking islands and peninsulas, such as in Southeast Asia. The Neptune Project consists of a network of underwater cables proposed to link Maine and Canada Maritime generation with the rest of New England, New York, and the mid-Atlantic areas.

Advanced Composite Conductors: Usually, transmission lines contain steel-core cables that support strands of aluminum wires, which are the primary conductors of electricity. New cores developed from composite materials are proposed to replace the steel core.

Objective: Allow more power through new or existing transmission rights of way.

Benefits: A new core consisting of composite fiber materials shows promise as stronger than steel-core aluminum conductors while 50 percent lighter in weight with up to 2.5 times less sag. The reduced weight and higher strength equate to greater current carrying capability as more current-carrying aluminum can be added to the line. This fact along with manufacturing advances, such as trapezoidal shaping of the aluminum strands, can reduce resistance by 10 percent, enable more compact designs with up to 50 percent reduction in magnetic fields, and reduce ice buildup compared to standard wire conductors. This technology can be integrated in the field by most existing reconductoring equipment.

Barriers: More experience is needed with the new composite cores to reduce total life-cycle costs.

Commercial Status: Research projects and test systems are in progress.

Transmission Line Configurations

Advances are being made in the configuration of transmission lines. New design processes coupled with powerful computer programs can optimize the height, strength, and positioning of transmission towers, insulators, and associated equipment in order to meet engineering standards appropriate for the conductor (e.g., distance from ground and tension for a given set of weather parameters).

Tower Design Tools: A set of tools is being perfected to analyze upgrades to existing transmission facilities or the installation of new facilities to increase their power-transfer capacity and reduce maintenance.

Objective: Ease of use and greater application of visualization techniques make the process more efficient and accurate when compared to traditional tools. Traditionally, lines have been rated conservatively. Careful analysis can discover the unused potential of existing facilities. Visualization tools can show the public the anticipated visual impact of a project prior to commencement.

Benefits: Avoids new right-of-way issues. The cost of upgrading the thermal rating has been estimated at approximately $7,000 per circuit mile, but reconductoring a 230-kV circuit costs on the order of $120,000 per mile compared with $230,000 per mile for a new steel-pole circuit (Lionberger and Duke 2001).

Barriers: This technology is making good inroads.

Commercial Status: Several companies offer commercial products and services.

Six-Phase and 12-Phase Transmission Line Configurations: The use of more than three phases for electric power transmission has been studied for many years. Using six or even 12 phases allows for greater power transfer capability within a particular right of way, and reduced EMFs because of greater phase cancellation. The key technical challenge is the cost and complexity of integrating such high-phase-order lines into the existing three-phase grid.

Modular Equipment

One way to gain flexibility for changing market and operational situations is to develop standards for the manufacture and integration of modular equipment.

Objective: Develop substation designs and specifications for equipment manufacturers to meet that facilitate the movement and reconfiguration of equipment in a substation to meet changing needs.

Benefits: Reduces overall the time and expense for transmission systems to adapt to the changing economic and reliability landscape.

Barriers: Requires transmission planners and substation designers to consider a broad range of operating scenarios. Also, developing industry standards can take a significant period, and manufacturers would need to offer conforming products.

Commercial Status: Utilities have looked for a certain amount of standardization and flexibility in this area for some time; however, further work remains to be done. National Grid (UK) has configured a number of voltage-support devices that use modular construction methods. As the system evolves, the equipment can be moved to locations where support is needed (PA Consulting Group 2001).

Universal Transformer: A single, standardized design capable of handling multiple voltage transformations in the mid ranges of 161/230/345/500 kV on a switch-selectable basis. Added features might be high portability, to facilitate emergency deployment from a "strategic reserve" of such transformers, plus the accommodation of high phase order transmission lines.

Exotic Transmission Alternatives

The following technical approaches have been proposed to reduce losses, increase capacity, and/or address situations where traditional energy transport mechanisms have shortcomings. In all cases, test configurations have been developed, but commercial implementations have yet to emerge.

Power Beaming (Wireless Power Transmission): Power beaming involves the wireless transmission of electric energy by means of either laser or microwave radiation. Near-term applications include transmission of electric energy for space applications (e.g., to orbiting satellites) from either a terrestrial- or space-based power generation platform. Other applications that have been studied include supporting human space exploration (e.g., lunar or Mars missions). Future applications might involve the beaming of energy from orbiting or even lunar-based solar power generators to terrestrial receivers, but to date the economics of such a system have remained elusive; proponents of such systems believe that they can be competitive within 15 to 25 years.

Ultra-High Voltage Levels: Because power is equal to the product of voltage times current, a highly effective approach to increasing the amount of power transmitted on a transmission line is to increase its operating voltage. Since 1969, the highest transmission voltage levels in North America have been 765 kV, (voltage levels up to 1,000 kV are in service elsewhere). Difficulties with utilizing higher voltages include the need for larger towers and larger rights of way to get the necessary phase separation, the ionization of air near the surface of the conductors because of high electric fields, the high reactive power generation of the lines, and public concerns about EMFs.

Active Reinforcing Equipment

Transmission System Devices

Implemented throughout the system, these devices include capacitors, phase shifters, static-var compensators (SVCs), thyristor-controlled series capacitors (TCSC), thyristor-controlled dynamic brakes, and other similar devices. Used to adjust system impedance, these devices can increase the transmission system's transfer capacity, support bus voltages by providing reactive power, or enhance dynamic or transient stability.

HVDC: With active control of real and reactive power transfer, HVDC can be modulated to damp oscillations or provide power-flow dispatch independent of voltage magnitudes or angles (unlike conventional AC transmission).

Objective: HVDC is used for long-distance power transport, linking asynchronous control areas, and real-time control of power flow.

Benefits: Stable transport of power over long distances where AC transmission lines need series compensation that can lead to stability problems. HVDC can run independent of system frequency and can control the amount of power sent through the line. This latter benefit is the same as for FACTS devices discussed below.

Barriers: Drawbacks include the high cost of converter equipment and the need for specially trained technicians to maintain the devices.

Commercial Status: Many long-distance HVDC links are in place around the world. Back-to-back converters link Texas, WSCC, and the Eastern Interconnection in the US. More installations are being planned.

FACTS Compensators: Flexible AC Transmission System (FACTS) devices use power electronics to adjust the apparent impedance of the system. Capacitor banks are applied at loads and substations to provide capacitive reactive power to offset the inductive reactive power typical of most power system loads and transmission lines. With long inter-tie transmission lines, series capacitors are used to reduce the effective impedance of the line. By adding thyristors to both of these types of capacitors, actively controlled reactive power is available using SVCs and TCSC devices, which are shunt- and series-controlled capacitors, respectively. The thyristors are used to adjust the total impedance of the device by switching individual modules. Unified power-flow controllers (UPFCs) also fall into this category.

Objective: FACTS devices are designed to control the flow of power through the transmission grid.

Benefits: These devices can increase the transfer capacity of the transmission system, support bus voltages by providing reactive power, or be used to enhance dynamic or transient stability.

Barriers: As with HVDC, the power electronics are expensive and specially trained technicians are needed to maintain them. In addition, experience is needed to fully understand the coordinated control strategy of these devices as they penetrate the system.

Commercial Status: As mentioned above, the viability of HVDC systems has already been demonstrated. American Electric Power (AEP) has installed a FACTS device in its system, and a new device was recently commissioned by the New York Power Authority (NYPA) to regulate flows in the northeast.

FACTS Phase-Shifting Transformers: Phase shifters are transformers configured to change the phase angle between buses; they are particularly useful for controlling the power flow on the transmission network. Adding thyristor control to the various tap settings of the phase-shifting transformer permits continuous control of the effective phase angle (and thus control of power flow).

Objective: Adjust power flow in the system.

Benefits: The key advantage of adding power electronics to what is currently a non-electronic technology is faster response time (less then one second vs. about one minute). However, traditional phase shifters still permit redirection of flows and thereby increase transmission system capacity.

Barriers: Traditional phase shifters are deployed today. The addition of the power electronics to these devices is relatively straightforward but increases expense and involves barriers similar to those noted for FACTS compensators.

Commercial Status: Tap-changing phase shifters are available today. Use of thyristor controls is emerging.

FACTS Dynamic Brakes: A dynamic brake is used to rapidly extract energy from a system by inserting a shunt resistance into the network. Adding thyristor controls to the brake permits addition of control functions, such as on-line damping of unstable oscillations.

Objective: Dynamic brakes enhance power system stability.

Benefits: This device can damp unstable oscillations triggered by equipment outages or system configuration changes.

Barriers: In addition the power electronics issues mentioned earlier, siting a dynamic brake and tuning the device in response to specific contingencies requires careful study.

Commercial Status: BPA has installed a dynamic brake on their system.

Energy-Storage Devices

The traditional function of an energy-storage device is to save production costs by holding cheaply generated off-peak energy that can be dispatched during peak-consumption periods. By virtue of its attributes, energy storage can also provide effective power system control with modest incremental investment. Different dispatch modes can be superimposed on the daily cycle of energy storage, with additional capacity reserved for the express purpose of providing these control functions.

Batteries: Batteries use converters to transform the DC in the storage device to the AC of the power grid. Converters also operate in the opposite direction to recharge the batteries.

Objective: Store energy generated in off-peak hours to be used for emergencies or on-peak needs.

Benefits: Battery converters use thyristors that, by the virtue of their ability to rapidly change the power exchange, can be utilized for a variety of real-time control applications ranging from enhancing transient to preconditioning the area control error for automatic generator control enhancement. During their operational lifetime, batteries have a small impact on the environment. For distributed resources, batteries do not need to be as large as for large-scale generation, and they become important components for regulating micro-grid power and allowing interconnection with the rest of the system.

Barriers: The expense of manufacturing and maintaining batteries has limited their impact in the industry.

Commercial Status: Several materials are used to manufacture batteries though large arrays of lead-acid batteries continue to be the most popular for utility installations. Interest is also growing in so-called "flow batteries" that charge and discharge a working fluid exchanged between two tanks. The emergence of the distributed energy business has increased the interest in deploying batteries for regional energy storage. One of the early battery installations that demonstrated grid benefit was a joint project between EPRI and Southern California Edison at the Chino substation in southern California.

Super-conducting Magnetic Energy Storage (SMES): SMES uses cryogenic technology to store energy by circulating current in a super-conducting coil.

Objective: Store energy generated in off-peak hours to be used for emergencies or on-peak needs.

Benefits: The benefits are similar to those for batteries. SMES devices are efficient because of their super-conductive properties. They are also very compact for the amount of energy stored.

Barriers: As with the super-conducting equipment mentioned in the passive equipment section above, SMES entails costs for the cooling system, the special protection needed in the event the super-conducting device quenches, and the specialized skills required to maintain the device.

Commercial Status: Several SMES units have been commissioned in North America. They have been deployed at Owens Corning to protect plant processes, and at Wisconsin Public Service to address low-voltage and grid instability issues.

Pumped Hydro and Compressed-Air Storage: Pumped hydro consists of large ponds with turbines that can be run in either pump or generation modes. During periods of light load (e.g., night) excess, inexpensive capacity drives the pumps to fill the upper pond. During heavy load periods, the water generates electricity into the grid. Compressed air storage uses the same principle except that large, natural underground vaults are used to store air under pressure during light-load periods.

Objective: This technology helps shave peak and can help in light-load, high-voltage situations.

Benefits: These storage systems behave like conventional generation and have the benefit of producing additional generation sources that can be dispatched to meet various energy and power needs of the system. Air emission issues can be mitigated when base generation is used in off-peak periods as an alternative to potentially high-polluting peaking units during high use periods.

Barriers: Pumped hydro, like any hydro generation project, requires significant space and has corresponding ecological impact. The loss of efficiency between pumping and generation as well as the installation and maintenance costs must be outweighed by the benefits.

Commercial Status: Pumped hydro projects are sprinkled across North America. A compressed-air storage plant was built in Alabama, and a proposed facility in Ohio may become the world's largest.

Flywheels: Flywheels spin at high velocity to store energy. As with pumped hydro or compressed-air storage, the flywheel is connected to a motor that either accelerates the flywheel to store energy or draws energy to generate electricity. The flywheel rotors are specially designed to significantly reduce losses. Super conductivity technology has also been deployed to increase efficiency.

Objective: Shave peak energy demand and help in light-load, high-voltage situations. As a distributed resource, flywheels enhance power quality and reliability.

Benefits: Flywheel technology has reached low-loss, high-efficiency levels using rotors made of composite materials running in vacuum spaces. Emissions are not an issue for flywheels, except those related to the energy expended to accelerate and maintain the flywheel system.

Barriers: The use of super-conductivity technology faces the same barriers as noted above under super-conducting cables and SMES. High-energy-storage flywheels require significant space and the high-speed spinning mass can be dangerous if the equipment fails.

Commercial Status: Flywheel systems coupled with batteries are making inroads for small systems (e.g., computer UPS, local loads, electric vehicles). Flywheels rated in the 100 to 200 kW range are proposed for development in the near term.

Controllable Load

Fast-acting load control is an important element in active measures for enhancing the transmission grid. Automatic load shedding (under-frequency, under-voltage), operator-initiated interruptible load, demand-side management programs, voltage reduction, and other load-curtailment strategies have long been an integral part of coping with unforeseen contingencies as a last resort, and/or as a means of assisting the system during high stress, overloaded conditions. Future advances in load-control technology will leverage the advent of real-time pricing, enabling consumers to "back off" their loads (either automatically through grid-friendly appliances or through manual intervention) when the price is right.

Price-Responsive Load: The electricity industry has been characterized by relatively long-term contracts for electricity use. As the industry restructures to be more market-driven, adjusting demand based on market signals will become an important tool for grid operators.

Objective: Inform energy users of system conditions though price signals that nudge consumption into positions that make the system more reliable and economic.

Benefits: The approach reduces the need for new transmission and siting of new generation. Providing incentives to change load in appropriate regions of the system can stabilize energy markets and enhance system reliability. Shifting load from peak periods to less polluting off-peak periods can reduce emissions.

Barriers: The vast number of loads in the system make communication and coordination difficult. Also, using economic signals in real time or near-real time to affect demand usage has not been part of the control structure that has been used by the industry for decades. A common vision and interface standards are needed to coordinate the information exchange required.

Commercial Status: Demand-management programs have been implemented in various areas of the country. These have relied on centralized control. With the advent of the Internet and new distributed information technology approaches, firms are emerging to take advantage of this technology with a more distributed control strategy.

Intelligent Building Systems: Energy can be saved through increasing the efficient operation of buildings and factories. Coordinated utilization of cooling, heating, and electricity in these establishments can significantly reduce energy consumption. Operated in a system that supports price-responsive load, intelligent building systems can benefit system operations. Note: these systems may have their own, local generation. Such systems have the option of selling power to the grid as well as buying power.

Objective: Reduce energy costs and provide energy management resources to stabilize energy markets and enhance system reliability.

Benefits: Such systems optimize energy consumption for the building operators and may provide system operators with energy by reducing load or increasing local generation based on market conditions.

Barriers: These systems require a greater number of sensors and more complex control schemes than are common today. Should energy market access become available at the building level, the price incentives would increase.

Commercial Status: Pilot projects have been implemented throughout the country.

Generation

Devices that are designed to improve the efficiency or interface of generation resources can be used for power system control. Advanced converter concepts will play an increasing role, providing power conversion between DC and AC power, for resources such as wind, solar, and any non-synchronous generation. Converter concepts such as pulse width modulation and step-wave inverters would be particularly useful for incorporating DC sources into the grid or providing an asynchronous generation interface. Asynchronous generation has been proposed for increasing the efficiency of hydroelectric generation, which would also have the advantage of providing control functions such as the ability to modify the effective inertia of generators.

Distributed Generation (DG): Fuel cells, micro-turbines, diesel generators, and other technologies are being integrated using power electronics. As these distributed resources increase in number, they can become a significant resource for reliable system operations. Their vast numbers and teaming with local load put them in a similar category to the controllable load discussed above.

Objective: Address local demand cost-effectively.

Benefits: DG is generally easier to site, entails smaller individual financial outlay, and can be more rapidly installation than large-scale generation. DG can supply local load or sell into the system and offers owners self-determination. Recovery and use of wase heat from some DG greatly increases energy efficiency.

Barriers: Volatility of fuel costs and dependence on the fuel delivery infrastructure creates financial and reliability risks. DG units require maintenance and operations expertise, and utilities can set up discouraging rules for interconnection. System operators have so far had difficulty coordinating the impact of DG.

Commercial Status: Deployment of DG units continues to increase. As with controllable load, system operations are recognizing the potential positive implications of DG to stabilize market prices and enhance system reliability though this requires a different way of thinking from the traditional, hierarchical control paradigm.

Real-time Monitoring

This section discusses the impact of new hardware technology on the capacity to sense in real time the loading and limits of individual system devices as well as the overall state of the system. The capability of the electricity grid is restricted through a combination of the limits on individual devices and the composite loadability of the system. Improving monitoring to determine these limits in real time and to measure the system state directly can increase grid capability.

Power-System Device Sensors

The operation of most of the individual devices in a power system (such as transmission lines, cables, transformers, and circuit breakers) is limited by each device's thermal characteristics. In short, trying to put too much power through a device will cause it to heat excessively and eventually fail. Because the limits are thermal, their actual values are highly dependent upon each device's heat dissipation, which is related to ambient conditions. The actual flow of power through most power-system devices is already adequately measured. The need is for improved sensors to dynamically determine the limits by directly or indirectly measuring temperature.

Direct Measurement of Conductor Sag: For overhead transmission lines the ultimate limiting factor is usually conductor sag. As wires heat, they expand, causing the line to sag. Too much sag will eventually result in a short circuit because of arcing from the line to whatever is underneath.

Objective: Dynamically determine line capacity by directly measuring the sag on critical line segments.

Benefits: Dynamically determined line ratings allow for increased power capacity under most operating conditions.

Barriers: Requires continuous monitoring of critical spans. Cost depends on the number of critical spans that must be monitored, the cost of the associated sensor technology, and ongoing cost of communication.

Commercial Status: Pre-commercial units are currently being tested. Approaches include either video or the use of differential GPS. EPRI currently is testing a video-based "sagometer." An alternative is to use differential GPS to directly measure sag. Differential GPS has been demonstrated to be accurate significantly below half a meter.

Indirect Measurement of Conductor Sag: Transmission line sag can also be estimated by physically measuring the conductor temperature using an instrument directly mounted on the line and/or a second instrument that measures conductor tension at the insulator supports.

Objective: Dynamically determine the line capacity.

Benefits: Dynamically determined line ratings allow for increased power capacity under most operating conditions.

Barriers: Requires continuous monitoring of critical spans. Cost depends upon the number of critical spans that must be monitored, the cost of the associated sensor technology, and ongoing costs of communication.

Commercial Status: Commercial units are available.

Indirect Measurement of Transformer Coil Temperature: Similar to transmission line operation, transformer operation is limited by thermal constraints. However, transformers constraints are localized hot spots on the windings that result in breakdown of insulation.

Objective: Dynamically determine transformer capacity.

Benefits: Dynamically determined transformer ratings allow for increased power capacity under most operating conditions.

Barriers: The simple use of oil temperature measurements is usually considered to be unreliable.

Commercial Status: Sophisticated monitoring tools are now commercially available that combine several different temperature and current measurements to dynamically determine temperature hot spots.

Underground/Submarine Cable Monitoring/Diagnostics: The below-surface cable systems described above require real-time monitoring to maximize their use and warn of potential failure.

Objective: Incorporate real-time sensing equipment to detect potentially hazardous operating situations as well as dynamic limits for safe flow of energy.

Benefits: Monitoring equipment maximizes the use of the transmission asset, mitigates the risk of failure and the ensuing expense of repair, and supports preventive maintenance procedures. The basic sensing and monitoring technology is available today.

Barriers: The level of sophistication of the sensing and monitoring equipment adds to the cost of the cable system. The use of dynamic limits must also be integrated into system operation procedures and the associated tools of existing control facilities.

Commercial Status: Newer cable systems are being designed with monitoring/diagnostics in mind. Cable temperature, dynamic thermal rating calculations, partial discharge detection, moisture ingress, cable damage, hydraulic condition (as appropriate), and loss detection are some of the sensing functions being put in place. Multifunctional cables are also being designed and deployed (particularly submarine cables) that include communications capabilities. Monitoring is being integrated directly into the manufacturing process of these cables.

Direct System-State Sensors

In some situations, transmission capability is not limited by individual devices but rather by region-wide dynamic loadability constraints. These include transient stability limitations, oscillatory stability limitations, and voltage stability limitations. Because the time frame associated with these phenomena is much shorter than that associated with thermal overloads, predicting, detecting and responding to these events requires much faster real-time state sensors than for thermal conditions. The system state is characterized ultimately by the voltage magnitudes and angles at all the system buses. The goal of these sensors is to provide these data at a high sampling rate.

Power-System Monitors

Objective: Collect essential signals (key power flows, bus voltages, alarms, etc.) from local monitors available to site operators, selectively forwarding to the control center or to system analysts.

Benefits: Provides regional surveillance over important parts of the control system to verify system performance in real time.

Barriers: Existing SCADA and Energy Management Systems provide low-speed data access for the utility's infrastructure. Building a network of high-speed data monitors with intra-regional breadth requires collaboration among utilities within the interconnected power system.

Commercial Status: BPA has developed a network of dynamic monitors collecting high-speed data, first with the power system analysis monitor (PSAM), and later with the portable power system monitor (PPSM), both early examples of WAMS products.

Phasor Measurement Units (PMUs)

Objective: PMUs are synchronized digital transducers that can stream data, in real time, to phasor data concentrator (PDC) units. The general functions and topology for this network resemble those for dynamic monitor networks. Data quality for phasor technology appears to be very high, and secondary processing of the acquired phasors can provide a broad range of signal types.

Benefits: Phasor networks have best value in applications that are mission critical and that involve truly wide-area measurements.

Barriers: Establishing PMU networks is straightforward and has already been done. The primary impediment is cost and assuring value for the investment (making best use of the data collected).

Commercial Status: PMU networks have been deployed at several utilities across the country.